ENVIRONMENTAL PROTECTION AGENCY
40 CFR Part 80
[EPA-HQ-OAR-2005-0161; FRL-XXXX-X]
RIN 2060-A081

Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Under the Clean Air Act Section 211(o), as amended by the Energy Independence and Security Act of 2007 (EISA), the Environmental Protection Agency is required to promulgate regulations implementing changes to the Renewable Fuel Standard program. The revised statutory requirements specify the volumes of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel. This action finalizes the regulations that implement the requirements of EISA, including the cellulosic, biomass-based diesel, advanced biofuel, and renewable fuel standards that will apply to all gasoline and diesel produced or imported in 2010. The final regulations make a number of changes to the current Renewable Fuel Standard program while retaining many elements of the compliance and trading system already in place. This final rule also implements the revised statutory definitions and criteria, most notably the new greenhouse gas emission thresholds for renewable fuels and new limits on renewable biomass feedstocks. This rulemaking marks the first time that greenhouse gas emission performance is being applied in a regulatory context for a nationwide program. As mandated by the statute, our greenhouse gas emission assessments consider the full lifecycle emission impacts of fuel production from both direct and indirect emissions, including significant emissions from land use changes. In carrying out our lifecycle analysis we have taken steps to ensure that the lifecycle estimates are based on the latest and most up-to-date science. The lifecycle greenhouse gas assessments reflected in this rulemaking represent significant improvements in analysis based on information and data received since the proposal. However, we also recognize that lifecycle GHG assessment of biofuels is an evolving discipline and will continue to revisit our lifecycle analyses in the future as new information becomes available. EPA plans to ask the National Academy of Sciences for assistance as we move forward. Based on current analyses we have determined that ethanol from corn starch will be able to comply with the required greenhouse gas (GHG)

threshold for renewable fuel. Similarly, biodiesel can be produced to comply with the 50% threshold for biomass-based diesel, sugarcane with the 50% threshold for advanced biofuel and multiple cellulosic-based fuels with their 60% threshold. Additional fuel pathways have also been determined to comply with their thresholds. The assessment for this rulemaking also indicates the increased use of renewable fuels will have important environmental, energy and economic impacts for our Nation.

DATES: This final rule is effective on July 1, 2010, and the percentage standards apply to all gasoline and diesel produced or imported in 2010. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of July 1, 2010.

ADDRESSES: EPA has established a docket for this action under Docket ID No. **EPA-HQ-OAR-2005-0161.** All documents in the docket are listed in the www.regulations.gov web site. Although listed in the index, some information is not publicly available, e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW, Washington DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Julia MacAllister, Office of Transportation and Air Quality, Assessment and Standards Division, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor MI 48105; Telephone number: 734-214-4131; Fax number: 734-214-4816; E-mail address: macallister.julia@epa.gov, or Assessment and Standards Division Hotline; telephone number (734) 214-4636; E-mail address asdinfo@epa.gov.

SUPPLEMENTARY INFORMATION:

General Information

I. Does this Final Rule Apply to Me?

Entities potentially affected by this final rule are those involved with the production, distribution, and sale of transportation fuels, including gasoline and diesel fuel or renewable fuels such as ethanol and biodiesel. Regulated categories include:

Category	NAICS[1] Codes	SIC[2] Codes	Examples of Potentially Regulated Entities
Industry	324110	2911	Petroleum Refineries
Industry	325193	2869	Ethyl alcohol manufacturing
Industry	325199	2869	Other basic organic chemical manufacturing
Industry	424690	5169	Chemical and allied products merchant wholesalers
Industry	424710	5171	Petroleum bulk stations and terminals
Industry	424720	5172	Petroleum and petroleum products merchant wholesalers
Industry	454319	5989	Other fuel dealers

[1] North American Industry Classification System (NAICS)
[2] Standard Industrial Classification (SIC) system code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this final action. This table lists the types of entities that EPA is now aware could potentially be regulated by this final action. Other types of entities not listed in the table could also be regulated. To determine whether your activities would be regulated by this final action, you should carefully examine the applicability criteria in 40 CFR part 80. If you have any questions regarding the applicability of this final action to a particular entity, consult the person listed in the preceding section.

Outline of This Preamble

I. Executive Summary

Through this final rule, the U.S. Environmental Protection Agency is revising the National Renewable Fuel Standard program to implement the requirements of the Energy Independence and Security Act of 2007 (EISA). EISA made significant changes to both the structure and the magnitude of the renewable fuel program created by the Energy Policy Act of 2005 (EPAct). The EISA fuel program, hereafter referred to as RFS2, mandates the use of 36 billion gallons of renewable fuel by 2022--a nearly a five-fold increase over the highest volume specified by EPAct. EISA also established four separate categories of renewable fuels, each with a separate volume mandate and each with a specific lifecycle greenhouse gas emission threshold. The categories are renewable fuel, advanced biofuel, biomass-based diesel, and cellulosic biofuel. There is a notable increase in the mandate for cellulosic biofuels in particular. EISA increased the cellulosic biofuel mandate to 16 billion gallons by 2022, representing the bulk of the increase in the renewable fuels mandate.

EPA's proposed rule sought comment on a multitude of issues, ranging from how to interpret the new definitions for renewable biomass to the Agency's proposed methodology for conducting the greenhouse gas lifecycle assessments required by EISA. The decisions presented in this final rule are heavily informed by the many public comments we received on the proposed rule. In addition, and as with the proposal, we sought input from a wide variety of stakeholders. The Agency has had multiple meetings and discussions with renewable fuel producers, technology companies, petroleum refiners and importers, agricultural associations, lifecycle experts, environmental groups, vehicle manufacturers, states, gasoline and petroleum marketers, pipeline owners and fuel terminal operators. We also have worked closely with other Federal agencies and in particular with the Departments of Energy and Agriculture.

This section provides an executive summary of the final RFS2 program requirements that EPA is implementing as a result of EISA. The RFS2 program will replace the RFS1 program promulgated on May 1, 2007 (72 FR 23900)[1]. Details of the final requirements can be found in Sections II and III, with certain lifecycle aspects detailed in Section V.

This section also provides a summary of EPA's assessment of the environmental and economic impacts of the use of higher renewable fuel volumes. Details of these analyses can be found in Sections IV through IX and in the Regulatory Impact Analysis (RIA).

A. Summary of New Provisions of the RFS Program

Today's notice establishes new regulatory requirements for the RFS program that will be implemented through a new Subpart M to 40 CFR Part 80. EPA is maintaining

[1] To meet the requirements of EPAct, EPA had previously adopted a limited program that applied only to calendar year 2006. The RFS1 program refers to the general program adopted in the May 2007 rulemaking.

several elements of the RFS1 program such as regulations governing the generation, transfer, and use of Renewable Identification Numbers (RINs). At the same time, we are making a number of updates to reflect the changes brought about by EISA

1. Required Volumes of Renewable Fuel

The RFS program is intended to require a minimum volume of renewable fuel to be used each year in the transportation sector. In response to EPAct 2005, under RFS1 the required volume was 4.0 billion gallons in 2006, ramping up to 7.5 billion gallons by 2012. Starting in 2013, the program also required that the total volume of renewable fuel contain at least 250 million gallons of fuel derived from cellulosic biomass.

In response to EISA, today's action makes four primary changes to the volume requirements of the RFS program. First, it substantially increases the required volumes and extends the timeframe over which the volumes ramp up through at least 2022. Second, it divides the total renewable fuel requirement into four separate categories, each with its own volume requirement. Third, it requires, with certain exceptions applicable to existing facilities, that each of these mandated volumes of renewable fuels achieve certain minimum thresholds of GHG emission performance. Fourth, it requires that all renewable fuel be made from feedstocks that meet the new definition of renewable biomass including certain land use restrictions. The volume requirements in EISA are shown in Table I.A.1-1.

Table I.A.1-1
Renewable Fuel Volume Requirements for RFS2 (billion gallons)

	Cellulosic biofuel requirement	Biomass-based diesel requirement	Advanced biofuel requirement	Total renewable fuel requirement
2009	n/a	0.5	0.6	11.1
2010	0.1	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.5	1.0	2.0	15.2
2013	1.0	a	2.75	16.55
2014	1.75	a	3.75	18.15
2015	3.0	a	5.5	20.5
2016	4.25	a	7.25	22.25
2017	5.5	a	9.0	24.0
2018	7.0	a	11.0	26.0
2019	8.5	a	13.0	28.0
2020	10.5	a	15.0	30.0
2021	13.5	a	18.0	33.0
2022	16.0	a	21.0	36.0
2023+	b	b	b	b

[a] To be determined by EPA through a future rulemaking, but no less than 1.0 billion gallons.
[b] To be determined by EPA through a future rulemaking.

As shown in the table, the volume requirements are not exclusive, and generally result in nested requirements. Any renewable fuel that meets the requirement for cellulosic biofuel or biomass-based diesel is also valid for meeting the advanced biofuel requirement. Likewise, any renewable fuel that meets the requirement for advanced biofuel is also valid for meeting the total renewable fuel requirement. See Section V.C for further discussion of which specific types of fuel may qualify for the four categories shown in Table I.A.1-1.

2. Standards for 2010 and Effective Date for New Requirements

While EISA established the renewable fuel volumes shown in Table I.A.1-1, it also requires that the Administrator set the standards based on these volumes each November for the following year based in part on information provided from the Energy Information Agency (EIA). In the case of the cellulosic biofuel standard, section 211(o)(7)(D) of EISA specifically requires that the standard be set based on the volume projected to be available during the following year. If the volume is lower than the level shown in Table I.A.1-1, then EISA allows the Administrator to also lower the advanced biofuel and total renewable fuel standards each year accordingly. Given the implications of these standards and the necessary judgment that can't be reduced to a formula akin to the RFS1 regulations, we believe it is appropriate to set the standards through a notice-and-comment rulemaking process. Thus, for future standards, we intend to issue an

NPRM by summer and a final rule by November 30 of each year in order to determine the appropriate standards applicable in the following year. However, in the case of the 2010 standards, we are finalizing them as part of today's action.

a. 2010 Standards

While we proposed that the cellulosic biofuel standard would be set at the EISA-specified level of 100 million gallons for 2010, based on analysis of information available at this time, we no longer believe the full volume can be met. Since the proposal, we have had detailed discussions with over 30 companies that are in the business of developing cellulosic biofuels and cellulosic biofuel technology. Based on these discussions, we have found that many of the projects that served as the basis for the proposal have been put on hold, delayed, or scaled back. At the same time, there have been a number of additional projects that have developed and are moving forward. As discussed in Section IV.B.3, the timing for many of the projects indicates that while few will be able to provide commercial volumes for 2010, an increasing number will come on line in 2011, 2012, and 2013. The success of these projects is then expected to accelerate growth of the cellulosic biofuel industry out into the future. EIA provided us with a projection on October 29, 2009 of 5.04 million gallons (6.5 million ethanol-equivalent gallons) of cellulosic biofuel production for 2010. While our company-by-company assessment varies from EIA's, as described in Section IV.B.3., and actual cellulosic production volume during 2010 will be a function of developments over the course of 2010, we nevertheless believe that 5 million gallons (6.5 million ethanol equivalent) represents a reasonable, yet achievable level for the cellulosic standard for 2010. While this is lower than the level specified in EISA, no change to the advanced biofuel and total renewable fuel standards is warranted. With the inclusion of an energy-based Equivalence Value for biodiesel and renewable diesel, 2010 compliance with the biomass-based diesel standard will be more than enough to ensure compliance with the advanced biofuel standard for 2010.

Today's rule also includes special provisions to account for the 2009 biomass-based diesel volume requirements in EISA. As described in the NPRM, in November 2008 we used the new total renewable fuel volume of 11.1 billion gallons from EISA as the basis for the 2009 total renewable fuel standard that we issued under the RFS1 regulations.[2] While this approach ensured that the total mandated renewable fuel volume required by EISA for 2009 was used, the RFS1 regulatory structure did not provide a mechanism for implementing the 0.5 billion gallon requirement for biomass-based diesel nor the 0.6 billion gallon requirement for advanced biofuel. As we proposed, and as is described in more detail in Section II.E.2, we are addressing this issue in today's rule by combining the 2010 biomass-based diesel requirement of 0.65 billion gallons with the 2009 biomass based diesel requirement of 0.5 billion gallons to require that obligated parties meet a combined 2009/2010 requirement of 1.15 billion gallons by the end of the 2010 compliance year. No similar provisions are required in order to fulfill the 2009 advanced biofuel volume mandate.

[2] 73 FR 70643, November 21, 2008

The resulting 2010 standards are shown in Table I.A.2-1. These standards represent the fraction of a refiner's or importer's gasoline and diesel volume which must be renewable fuel. Additional discussion of the 2010 standards can be found in Section II.E.1.b.

Table I.A.2-1
Standards for 2010

Cellulosic biofuel	0.004%
Biomass-based diesel	1.10%
Advanced biofuel	0.61%
Renewable fuel	8.25%

b. Effective Date

Under CAA section 211(o) as modified by EISA, EPA is required to revise the RFS1 regulations within one year of enactment, or December 19, 2008. Promulgation by this date would have been consistent with the revised volume requirements shown in Table I.A.1-1 that begin in 2009 for certain categories of renewable fuel. As described in the NPRM, we were not able to promulgate final RFS2 program requirements by December 19, 2008.

Under today's rule, the transition from using the RFS1 regulatory provisions regarding registration, RIN generation, reporting, and recordkeeping to using comparable provisions in this RFS2 rule will occur on July 1, 2010. This is the start of the 1st quarter following completion of the statutorily required 60-day Congressional Review period for such a rulemaking as this. This will provide adequate lead time for all parties to transition to the new regulatory requirements, including additional time to prepare for RFS2 implementation for those entities who may find it helpful, especially those covered by the RFS program for the first time. In addition, making the transition at the end of the quarter will help simplify the recordkeeping and reporting transition to RFS2. To facilitate the volume obligations being based on the full years gasoline and diesel production, and to enable the smooth transition from the RFS1 to RFS2 regulatory provisions, Renewable Identification Numbers (RINs - which are used in the program for both credit trading and for compliance demonstration) that were generated under the RFS1 regulations will continue to be valid for compliance with the RFS2 obligations. Further discussion of transition issues can be found in Sections II.A and II.G.4, respectively.

According to EISA, the renewable fuel obligations applicable under RFS2 apply on a calendar basis. That is, obligated parties must determine their renewable volume obligations (RVOs) at the end of a calendar year based on the volume of gasoline or diesel fuel they produce during the year, and they must demonstrate compliance with their RVOs in an annual report that is due two months after the end of the calendar year.

For 2010, today's rule will follow this same general approach. The four RFS2 RVOs for each obligated party will be calculated on the basis of all gasoline and diesel produced or imported on and after January 1, 2010, through December 31, 2010. Obligated parties will be required to demonstrate by February 28 of 2011 that they obtained sufficient RINs to satisfy their 2010 RVOs. We believe this is an appropriate approach as it is more consistent with Congress' provisions in EISA for 2010, and there is adequate lead time for the obligated parties to achieve compliance.

The issue for EPA to resolve is how to apply the four volume mandates under EISA for calendar year 2010. These volume mandates are translated into applicable percentages that obligated parties then use to determine their renewable fuel volume obligations based on the gasoline and diesel they produce or import in 2010. There are three basic approaches that EPA has considered, based on comments on the proposal. The first is the approach adopted in this rule – the four RFS2 applicable percentages are determined based on the four volume mandates covered by this rule, and the renewable volume obligation for a refiner or importer will be determined by applying these percentages to the volume of gasoline and diesel fuel they produce during calendar year 2010. Under this approach, there is no separate applicable percentage under RFS1 for 2010, however RINs generated in 2009 and 2010 under RFS1 can be used to meet the four volume obligations for 2010 under the RFS2 regulations. Another option, which was considered and rejected by EPA, is much more complicated – (1) determine an RFS1 applicable percentage based on just the total renewable fuel volume mandate, using the same total volume for renewable fuel as used in the first approach, and require obligated parties to apply that percentage to the gasoline produced from January 1, 2010 until the effective date of the RFS2 regulations, and (2) determine the four RFS2 applicable percentages as discussed above, but require obligated parties to apply them to only the gasoline and diesel in 2010 after the effective date of the RFS2 regulations. Of greater concern than its complexity, the second approach fails to ensure that the total volumes for three of the volume mandates are met for 2010. In effect EPA would be requiring that obligated parties use enough cellulosic biofuel, biomass-based diesel, and advanced biofuel to meet approximately 75% of the total volumes required for these fuels under EISA. While the total volume mandate under EISA for renewable fuel would likely be met, the other three volumes mandates would only be met in part. The final option would involve delaying the RFS2 requirements until January 1, 2011, which would avoid the complexity of the second approach but would be even less consistent with EISA's requirements.

The approach adopted in this rule is clearly the most consistent with EISA's requirement of four different volume mandates for all of calendar year 2010. In addition, EPA is confident that obligated parties have adequate lead-time to comply with the four volume requirements under the approach adopted in this rule. The volume requirements are achieved by obtaining the appropriate number of RINs from producers of the renewable fuel. The obligated parties do not need lead time for construction or investment purposes, as they are not changing the way they produce gasoline or diesel, do not need to design to install new equipment, or take other actions that require longer lead time. Obtaining the appropriate amount of RINs involves contractual or other arrangements with renewable fuel producers or other holders of RINs. Obligated parties now have experience implementing RFS1, and the actions needed to comply under the RFS2 regulations are a continuation of these kinds of RFS1 activities. In addition, an adequate supply of RINs is expected to be available for compliance by obligated parties. RFS1 RINs have been produced throughout 2009 and continue to be produced since the beginning of 2010. There has been and will be no gap or lag in the production of RINS, as the RFS1 regulations continue in effect and require that renewable fuel producers generate RINs for the renewable fuel they produce. These 2009 and 2010 RFS1 RINs will be available and can be used towards the volume requirements of obligated parties for 2010. These RFS1 RINS combined with the RFS2 RINs that will be generated by renewable fuel producers are expected to provide an adequate supply of RINs to ensure compliance for all of the renewable volume mandates. For further discussion of the expected supply of renewable fuel, see section IV.

In addition, obligated parties have received adequate notice of this obligation. The proposed rule called for obligated parties to meet the full volume mandates for all four volume mandates, and to base their volume obligation on the volume of gasoline and diesel produced starting January 1, 2010. While the RFS2 regulations are not effective until after January 1, 2010, the same full year approach is being taken for the 2010 volumes of gasoline and diesel. Obligated parties have been on notice based on EPA's proposal, discussions with many stakeholders during the rulemaking, the issuance of the final rule itself, and publication of this rule in the Federal Register. As discussed above, there is adequate time for obligated parties to meet their 2010 volume obligations by the spring of 2011.

This approach does not impose any retroactive requirements. The obligation that is imposed under the RFS2 regulations is forward looking – by the spring of 2011, when compliance is determined, obligated parties must satisfy certain volume obligations. These future requirements are calculated in part based on volumes of gasoline and diesel produced prior to the effective date of the RFS2 regulations, but this does not make the RFS2 requirement retroactive in nature. The RFS2 regulations do not change in any way the legal obligations or requirements that apply prior to the effective date of the RFS2 regulations. Instead, the RFS2 requirements impose new requirements that must be met in the future. There is adequate lead time to comply with these RFS2 requirements, and they achieve a result that is more consistent with Congress' goals in establishing 4 volume mandates for calendar year 2010, and for these reasons EPA is adopting this approach for calendar year 2010.

Parties that intend to generate RINs, own and/or transfer them, or use them for compliance purposes after July 1, 2010 will need to register or re-register under the RFS2 provisions and modify their information technology (IT) systems to accommodate the changes we are finalizing today. As described more fully in Section II, these changes include redefining the D code within the RIN that identifies which standard a fuel qualifies for, adding a process for verifying that feedstocks meet the renewable biomass definition, and calculating compliance with four standards instead of one. EPA's registration system is available now for parties to complete the registration process.

Further details on this process can be found elsewhere in today's preamble as well as at http://www.epa.gov/otaq/regs/fuels/fuelsregistration.htm. Parties that produce motor vehicle, nonroad, locomotive, and marine (MVNRLM) diesel fuel but not gasoline will be newly obligated parties and may be establishing IT systems for the RFS program for the first time.

3. Analysis of Lifecycle Greenhouse Gas Emissions and Thresholds for Renewable Fuels

a. Background and Conclusions

A significant aspect of the RFS2 program is the requirement that the lifecycle GHG emissions of a qualifying renewable fuel must be less than the lifecycle GHG emissions of the 2005 baseline average gasoline or diesel fuel that it replaces; four different levels of reductions are required for the four different renewable fuel standards. These lifecycle performance improvement thresholds are listed in Table I.A.3-1. Compliance with each threshold requires a comprehensive evaluation of renewable fuels, as well as the baseline for gasoline and diesel, on the basis of their lifecycle emissions. As mandated by EISA, the greenhouse gas emissions assessments must evaluate the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions form land use changes) related to the full lifecycle, including all stages of fuel and feedstock production, distribution and use by the ultimate consumer.

Table I.A.3-1
Lifecycle GHG Thresholds Specified in EISA (percent reduction from baseline)

Renewable fuel[a]	20%
Advanced biofuel	50%
Biomass-based diesel	50%
Cellulosic biofuel	60%

[a] The 20% criterion generally applies to renewable fuel from new facilities that commenced construction after December 19, 2007.

It is important to recognize that fuel from the existing capacity of current facilities and the capacity of all new facilities that commenced construction prior to December 19, 2007 (and in some cases prior to December 31, 2009) are exempt, or grandfathered, from the 20% lifecycle requirement for the Renewable Fuel category. Therefore, EPA has in the discussion below emphasized its analysis on those plants and fuels that are likely to be used for compliance with the rule and would be subject to the lifecycle thresholds. Based on the analyses and approach described in Section V of this preamble, EPA is determining that ethanol produced from corn starch at a new facility (or expanded capacity from an existing) using natural gas, biomass or biogas for process energy and using advanced efficient technologies that we expect will be most typical of new production facilities will meet the 20% GHG emission reduction threshold compared to the 2005 baseline gasoline. We are also determining that biobutanol from corn starch meets the 20% threshold. Similarly, EPA is making the determination that biodiesel and renewable diesel from soy oil or waste oils, fats and greases will exceed the 50% GHG threshold for biomass-based diesel compared to the 2005 petroleum diesel baseline. In addition, we have now modeled biodiesel and renewable diesel produced from algal oils as complying with the 50% threshold for biomass-based diesel. EPA is also determining that ethanol from sugarcane complies with the applicable 50% GHG reduction threshold for advanced biofuels. The modeled pathways (feedstock and production technology) for cellulosic ethanol and cellulosic diesel would also comply with the 60% GHG reduction threshold applicable to cellulosic biofuels. As discussed later in section V, there are also other fuels and fuel pathways that we are determining will comply with the GHG thresholds.

Under EISA, EPA is allowed to adjust the GHG reduction thresholds downward by up to 10% if necessary based on lifecycle GHG assessment of biofuels likely to be available. Based on the results summarized above, we are not finalizing any adjustments to the lifecycle GHG thresholds for the four renewable fuel standard categories.

EPA recognizes that as the state of scientific knowledge continues to evolve in this area, the lifecycle GHG assessments for a variety of fuel pathways are likely to be updated. Therefore, while EPA is using its current lifecycle assessments to inform the regulatory determinations for fuel pathways in this final rule, as required by the statute, the Agency is also committing to further reassess these determinations and lifecycle estimates. As part of this ongoing effort, we will ask for the expert advice of the National Academy of Sciences, as well as other experts, and incorporate their advice and any updated information we receive into a new assessment of the lifecycle GHG emissions performance of the biofuels being evaluated in this final rule. EPA will request that the National Academy of Sciences evaluate the approach taken in this rule, the underlying science of lifecycle assessment, and in particular indirect land use change, and make recommendations for subsequent lifecycle GHG assessments on this subject. At this time we are estimating this review by the National Academy of Sciences may take up to two years. As specified by EISA, if EPA revises the analytical methodology for determining lifecycle greenhouse gas emissions, any such revision will apply to renewable fuel from new facilities that commence construction after the effective date of the revision.

b. Fuel Pathways Considered and Key Model Updates Since the Proposal

EPA is making the GHG threshold determination based on a methodology that includes an analysis of the full lifecycle, including significant emissions related to international land-use change**.** As described in more detail below and in Section V of this preamble, EPA has used the best available models for this purpose, and has incorporated many modifications to its proposed approach based on comments from the public and peer reviewers and developing science. EPA has also quantified the uncertainty associated with significant components of its analyses, including important factors affecting GHG emissions associated with international land use change. As discussed below, EPA has updated and refined its modeling approach since proposal in several important ways, and EPA is confident that its modeling of GHG emissions associated with international land use is comprehensive and provides a reasonable and scientifically robust basis for making the threshold determinations described above. As discussed below, EPA plans to continue to improve upon its analyses, and will update it in the future as appropriate.

Through technical outreach, the peer review process, and the public comment period, EPA received and reviewed a significant amount of data, studies, and information on our proposed lifecycle analysis approach. We incorporated a number of new, updated, and peer-reviewed data sources in our final rulemaking analysis including better satellite data for tracking land use changes and improved assessments of N2O impacts from agriculture. The new and updated data sources are discussed further in this section, and in more detail in Section V.

We also performed dozens of new modeling runs, uncertainty analyses, and sensitivity analyses which are leading to greater confidence in our results. We have updated our analyses in conjunction with, and based on, advice from experts from government, academia, industry, and not for profit institutions.

The new studies, data, and analysis performed for the final rulemaking impacted the lifecycle GHG results for biofuels in a number of different ways. In some cases, updates caused the modeled analysis of lifecycle GHG emissions from biofuels to increase, while other updates caused the modeled emissions to be reduced. Overall, the revisions since our proposed rule have led to a reduction in modeled lifecycle GHG emissions as compared to the values in the proposal. The following highlights the most significant revisions. Section V details all of the changes made and their relative impacts on the results.

Corn Ethanol: The final rule analysis found less overall indirect land use change (less land needed), thereby improving the lifecycle GHG performance of corn ethanol. The main reasons for this decrease are:

- Based on new studies that show the rate of improvement in crop yields as a function of price, crop yields are now modeled to increase in response to higher crop prices. When higher crop yields are used in the models, less land is needed domestically and globally for crops as biofuels expand.

- New research available since the proposal indicates that the corn ethanol production co-product, distillers grains and solubles (DGS), is more efficient as an animal feed (meaning less corn is needed for animal feed) than we had assumed in the proposal. Therefore, in our analyses for the final rule, domestic corn exports are not impacted as much by increased biofuel production as they were in the proposal analysis.

- Improved satellite data allowed us to more finely assess the types of land converted when international land use changes occur, and this more precise assessment led to a lowering of modeled GHG impacts. Based on previous satellite data, the proposal assumed cropland expansion onto grassland would require an amount of pasture to be replaced through deforestation. For the final rulemaking analysis we incorporated improved economic modeling of demand for pasture area and satellite data which indicates that pasture is also likely to expand onto existing grasslands. This reduced the GHG emissions associated with an amount of land use change.

However, we note that not all modeling updates necessarily reduced predicted GHG emissions from land use change. As one example, since the proposal a new version of the GREET model (Version 1.8C) has been released. EPA reviewed the new version and concluded that this was an improvement over the previous GREET release that was used in the proposal analysis (Version 1.8B). Therefore, EPA updated the GHG emission factors for fertilizer production used in our analysis to the values from the new GREET version. This had the result of slightly increasing the GHG emissions associated with fertilizer production and thus slightly increasing the GHG emission impacts of domestic agriculture.

For the final rule, EPA has analyzed a variety of corn ethanol pathways including ethanol made from corn starch using natural gas, coal, and biomass as process energy sources in production facilities utilizing both dry mill and wet mill processes. For corn starch ethanol, we also considered the technology enhancements likely to occur in the future such as the addition of corn oil fractionation or extraction technology, membrane separation technology, combined heat and power and raw starch hydrolysis.

Biobutanol from corn starch: In addition to ethanol from corn starch, for this final rule, we have also analyzed bio-butanol from corn starch. Since the feedstock impacts are the same as for ethanol from corn starch, the assessment for biobutanol reflects the differing impacts due to the production process and energy content of biobutanol compared to that of ethanol.

Soybean Biodiesel: The new information described above for corn ethanol also leads to lower modeled GHG impacts associated with soybean biodiesel. The revised assessment predicts less overall indirect land use change (less land needed) and less impact from the land use changed that does occur (due to updates in types of converted land assumed). In addition, the latest IPCC guidance indicates reduced domestic soybean N2O emissions, and updated USDA and industry data show reductions in biodiesel processing energy use and a higher co-product credit, all of which further reduced the modeled soybean biodiesel lifecycle GHG emissions. This has resulted in a significant improvement in our assessment of the lifecycle performance of soybean biodiesel as compared to the estimate in the proposal.

Biodiesel and Renewable Diesel from Algal Oil and Waste Fats and Greases: In addition to biodiesel from soy oil, biodiesel and renewable diesel from algal oil (should it reach commercial production) and biodiesel from waste oils, fats and greases have been modeled. These feedstock sources have little or no land use impact so the GHG impacts associate with their use in biofuel production are largely the result of energy required to produce the feedstock (in the case of algal oil) and the energy required to turn that feedstock into a biofuel.

Sugarcane Ethanol: Sugarcane ethanol was analyzed considering a range of technologies and assuming alternative pathways for dehydrating the ethanol prior to its use as a biofuel in the U.S. For the final rule, our analysis also shows less overall indirect land use change (less land needed) associated with sugarcane ethanol production. For the proposal, we assumed sugarcane expansion in Brazil would result in cropland expansion into grassland and lost pasture being replaced through deforestation. Based on newly available regional specific data from Brazil, historic trends, and higher resolution satellite data, in the final rule, sugarcane expansion onto grassland is coupled with greater pasture intensification, such that there is less projected impact on forests. Furthermore, new data provided by commenters showed reduced sugarcane ethanol process energy, which also reduced the estimated lifecycle GHG impact of sugarcane ethanol production.

Cellulosic Ethanol: We analyzed cellulosic ethanol production using both biochemical (enzymatic) and thermo-chemical processes with corn stover, switchgrass, and forestry thinnings and waste as feedstocks. For cellulosic diesel, we analyzed production using the Fischer-Tropsch process. For the final rule, we updated the cellulosic ethanol conversion rates based on new data provided by the National Renewable Energy Laboratory (NREL.) As a result of this update, the gallons per ton yields for switchgrass and several other feedstock sources increased in our analysis for the final rule, while the predicted yields from corn residue and several other feedstock sources decreased slightly from the NPRM values. In addition, we also updated our feedstock production yields based on new work conducted by the Pacific Northwest National Laboratory (PNNL). This analysis increased the tons per acre yields for several dedicated energy crops. These updates increased the amount of cellulosic ethanol projected to come from energy crops. While the increase in crop yields and conversion efficiency reduced the GHG emissions associated with cellulosic ethanol, there remains an increased demand for land to grow dedicated energy crops; this land use impact resulted in increased GHG emissions with the net result varying by the type of cellulosic feedstock source.

We note that several of the renewable fuel pathways modeled are still in early stages of development or commercialization and are likely to continue to develop as the industry moves toward commercial production. Therefore, it will be necessary to reanalyze several pathways using updated data and information as the technologies develop. For example, biofuel derived from algae is undergoing wide ranging development. Therefore for now, our algae analyses presume particular processes and energy requirements which will need to be reviewed and updated as this fuel source moves toward commercial production.

For this final rule we have incorporated a statistical analysis of uncertainty about critical variables in our pathway analysis. This uncertainty analysis is explained in detail in Section V and is consistent with the specific recommendations received through our peer review and public comments on the proposal. The uncertainty analysis focused on two aspects of indirect land use change - the types of land converted and the GHG emission associated with different types of land converted. In particular, our uncertainty analysis focused on such specific sources of information as the satellite imaging used to inform our assessment of land use trends and the specific changes in carbon storage expected from a change in land use in each geographic area of the world modeled. We have also performed additional sensitivity analyses including analysis of two yield scenarios for corn and soy beans to assess the impact of changes in yield assumptions.

This uncertainty analysis provides information on both the range of possible outcomes for the parameters analyzed, an estimate of the degree of confidence that the actual result will be within a particular range (in our case, we estimated a 95% confidence interval) and an estimate of the central tendency or midpoint of the GHG performance estimate.

In the proposal, we considered several options for the timeframe over which to measure lifecycle GHG impacts and the possibility of discounting those impacts. Based on peer review recommendations and other comments received, EPA is finalizing its assessments based on an analysis assuming 30 years of continued emission impacts after the program is fully phased in by 2022 and without discounting those impacts.

EPA also notes that it received significant comment on our proposed baseline lifecycle greenhouse gas assessment of gasoline and diesel (“petroleum baseline”). While EPA has made several updates to the petroleum analysis in response to comments (see Section V for further discussion), we are finalizing the approach based on our interpretation of the definition in the Act as requiring that the petroleum baseline represent an average of the gasoline and diesel fuel (whichever is being replaced by the renewable fuel) sold as transportation fuel in 2005.

As discussed in more detail later, the modeling results developed for purposes of the final rule provide a rich and comprehensive base of information for making the threshold determinations. There are numerous modeling runs, reflecting updated inputs to the model, sensitivity analyses, and uncertainty analyses. The results for different scenarios include a range and a best estimate or mid-point. Given the potentially conservative nature of the base crop yield assumption, EPA believes the actual crop yield in 2022 may be above the base yield; however we are not in a position to characterize how much above it might be. To the extent actual yields are higher, the base yield modeling results would underestimate to some degree the actual GHG emissions reductions compared to the baseline.

In making the threshold determinations for this rule, EPA weighed all of the evidence available to it, while placing the greatest weight on the best estimate value for the base yield scenario. In those cases where the best estimate for the base yield scenario exceeds the reduction threshold, EPA judges that there is a good basis to be confident that the threshold will be achieved and is determining that the bio-fuel pathway complies with the applicable threshold. To the extent the midpoint of the scenarios analyzed lies further above a threshold for a particular biofuel pathway, we have increasingly greater confidence that the biofuel exceeds the threshold.

EPA recognizes that certain commenters suggest that there is a very high degree of uncertainty associated in particular with determining international indirect land use changes and their emissions impacts, and because of this EPA should exclude any calculation of international indirect land use changes in its lifecycle analysis. Commenters say EPA should make the threshold determinations based solely on modeling of other sources of lifecycle emissions. In effect, commenters argue that the uncertainty of the modeling associated with international indirect land use change means we should use our modeling results but exclude that part of the results associated with international land use change.

For the reasons discussed above and in more detail in Section V, EPA rejects the view that the modeling relied upon in the final rule, which includes emissions associated with international indirect land use change, is too uncertain to provide a credible and reasonable scientific basis for determining whether the aggregate lifecycle emissions exceed the thresholds. In addition, as discussed elsewhere, the definition of lifecycle emissions includes significant indirect emissions associated with land use change. In deciding whether a bio-fuel pathway meets the threshold, EPA has to consider what it knows about all aspects of the lifecycle emissions, and decide whether there is a valid basis to find that the aggregate lifecycle emissions of the fuel, taking into account significant indirect emissions from land use change meets the threshold. Based on the analyses conducted for this rule, EPA has determined international indirect land use impacts are significant and therefore must be included in threshold compliance assessment.

If the international land use impacts were so uncertain that their impact on lifecycle GHG emissions could not be adequately determined, as claimed by commenters, this does not mean EPA could assume the international land use change emissions are zero, as commenters suggest. High uncertainty would not mean that emissions are small and can be ignored; rather it could mean that we could not tell whether they are large or small. If high uncertainty meant that EPA were not able to determine that indirect emissions from international land use change are small enough that the total lifecycle emissions meet the threshold, then that fuel could not be determined to meet the GHG thresholds of EISA and the fuel would necessarily have to be excluded from the program.

In any case, that is not the situation here as EPA rejects commenters suggestion and does not agree that the uncertainty over the indirect emissions from land use change is too high to make a reasoned threshold determination. Therefore biofuels with a significant international land use impact are included within this program.

c. Consideration of Fuel Pathways Not Yet Modeled

Not all biofuel pathways have been directly modeled for this rule. For example, while we have modeled cellulosic biofuel produced from corn stover, we have not modeled the specific GHG impact of cellulosic biofuel produced from other crop residues such as wheat straw or rice straw. Today, in addition to finalizing a threshold compliance determination for those pathways we specifically modeled, in some cases, our technical judgment indicates other pathways are likely to be similar enough to modeled pathways that we are also assured these similar pathways qualify. These pathways include fuels produced from the same feedstock and using the same production process but produced in countries other than those modeled. The agricultural sector modeling used for our lifecycle analysis does not predict any soybean biodiesel or corn ethanol will be imported into the U.S., or any imported sugarcane ethanol from production in countries other than Brazil. However, these rules do not prohibit the use in the U.S. of these fuels produced in countries not modeled if they are also expected to comply with the eligibility requirements including meeting the thresholds for GHG performance. Although the GHG emissions of producing these fuels from feedstock grown or biofuel produced in other countries has not been specifically modeled, we do not anticipate their use would impact our conclusions regarding these feedstock pathways. The emissions of producing these fuels in other countries could be slightly higher or lower than what was modeled depending on a number of factors. Our analyses indicate that crop yields for the crops in other countries where these fuels are also most likely to be produced are similar or lower than U.S. values indicating the same or slightly higher GHG impacts. Agricultural sector inputs for the crops in these other countries are roughly the same or lower than the U.S. pointing toward the same or slightly lower GHG impacts. If crop production were to expand due to biofuels in the countries where the models predict these biofuels might additionally be produced would tend to lower our assessment of international indirect impacts but could increase our assessment of the domestic (i.e., the country of origin) land use impacts. EPA believes, because of these offsetting factors along with the small amounts of fuel potentially coming from other countries, that incorporating fuels produced in other countries will not impact our threshold analysis. Therefore, fuels of the same fuel type, produced from the same feedstock using the same fuel production technology as modeled fuel pathways will be assessed the same GHG performance decisions regardless of country of origin. These pathways also include fuels that might be produced from similar feedstock sources to those already modeled and which are expected to have less or no indirect land use change. In such cases, we believe that in order to compete economically in the renewable fuel marketplace such pathways are likely to be at least as energy efficient as those modeled and thus have comparable lifecycle GHG performance. Based on these considerations, we are extending the lifecycle results for the fuel pathways already modeled to 5 broader categories of feedstocks. This extension of lifecycle modeling results is discussed further in Section V.C.

We have established five categories of biofuel feedstock sources under which modeled feedstock sources and feedstock sources similar to those modeled are grouped and qualify on the basis of our existing modeling. These are:

1. Crop residues such as corn stover, wheat straw, rice straw, citrus residue
2. Forest material including eligible forest thinnings and solid residue remaining from forest product production
3. Annual cover crops planted on existing crop land such as winter cover crops
4. Separated food and yard waste including biogenic waste from food processing
5. Perennial grasses including switchgrass and miscanthus

The full set of pathways for which we have been able to make a compliance decision are described in Section V.

Threshold determinations for certain other pathways were not possible at this time because sufficient modeling or data is not yet available. In some of these cases, we recognize that a renewable fuel is already being produced from an alternative feedstock. Although we have the data needed for analysis, we did not have sufficient time to complete the necessary lifecycle GHG impact assessment for this final rule. We will model and evaluate additional pathways after this final rule on the basis of current or likely commercial production in the near-term and the status of current analysis at EPA. EPA anticipates modeling grain sorghum ethanol, woody pulp ethanol, and palm oil biodiesel after this final rule and including the determinations in a rulemaking within 6 months. Our analyses project that they will be used in meeting the RFS2 volume standard in the near-term. During the course of the NPRM comment period, EPA received detailed information on these pathways and is currently in the process of analyzing these pathways. We have received comments on several additional feedstock/fuel pathways, including rapeseed/canola, camelina, sweet sorghum, wheat, and mustard seed, and we welcome parties to utilize the petition process described in Section V.C to request EPA to examine additional pathways.

We anticipate there could be additional cases where we currently do not have information on which to base a lifecycle GHG assessment perhaps because we are not yet aware of potential unique plant configurations or operations that could result in greater efficiencies than assumed in our analysis. In many cases, such alternative pathways could have been explicitly modeled as a reasonably straightforward extension of pathways we have modeled if the necessary information had been available. For example, while we have modeled specific enhancements to corn starch ethanol production such as membrane separation or corn oil extraction, there are likely other additional energy saving or co-product pathways available or under development by the industry. It is reasonable to also consider these alternative energy saving or co-product pathways based upon their technical merits. Other current or emerging pathways may require new analysis and modeling for EPA to fully evaluate compliance. For example, fuel pathways with feedstocks or fuel types not yet modeled by EPA may require additional modeling and, it follows, public comment before a determination of compliance can be made.

Therefore, for those fuel pathways that are different than those pathways EPA has listed in today's regulations, EPA is establishing a petition process whereby a party can petition the Agency to consider new pathways for GHG reduction threshold compliance. As described in Section V.C, the petition process is meant for parties with serious intention to move forward with production via the petitioned fuel pathway and who have moved sufficiently forward in the business process to show feasibility of the fuel pathway's implementation. In addition, if the petition addresses a fuel pathway that already has been determined to qualify as one or more types of renewable fuel under RFS (e.g., renewable fuel, or advanced biofuel), the pathway must have the potential to result in qualifying for a renewable fuel type for which it was not previously qualified. Thus, for example, the Agency will not undertake any additional review for a party wishing to get a modified LCA value for a previously approved fuel pathway if the desired new value would not change the overall pathway classification.

The petition must contain all the necessary information on the fuel pathway to allow EPA to effectively assess the lifecycle performance of the new fuel pathway. See Section V.C for a full description. EPA will use the data supplied via the petition and other pertinent data available to the Agency to evaluate whether the information for that fuel pathway, combined with information developed in this rulemaking for other fuel pathways that have been determined to exceed the threshold, is sufficient to allow EPA to evaluate the pathway for a determination of compliance. We expect such a determination would be pathway specific. For some fuel pathways with unique modifications or enhancements to production technologies in pathways otherwise modeled for the regulations listed today, EPA may be able to evaluate the pathway as a reasonably straight-forward extension of our current assessments. In such cases, we would expect to make a decision for that specific pathway without conducting a full rulemaking process. We would expect to evaluate whether the pathway is consistent with the definitions of renewable fuel types in the regulations, generally without going through rulemaking, and issue an approval or disapproval that applies to the petitioner. We anticipate that we will subsequently propose to add the pathway to the regulations. Other current or emerging fuel pathways may require significant new analysis and/or modeling for EPA to conduct an adequate evaluation for a compliance determination (e.g., feedstocks or fuel types not yet included in EPA's assessments for this regulation). For these pathways, EPA would give notice and seek public comment on a compliance determination under the annual rulemaking process established in today's regulations. If we make a technical determination of compliance, then we anticipate the fuel producer will be able to generate RINs for fuel produced under the additional pathway following the next available quarterly update of the EPA Moderated Transaction System (EMTS). EPA will process these petitions as expeditiously as possible, pathways are closer to the commercial production stage than others. In all events, parties are expected to begin this process with ample lead time as compared to their commercial start dates. Further discussion of this petition process can be found in Section V.C.

We note again that the continued work of EPA and others is expected to result in improved models and data sources, and that re-analysis based on such updated information could revise these determinations. Any such reassessment that would impact compliance would necessarily go through rulemaking and would only be applicable to production from future facilities after the revised rule was finalized, as required by EISA.

4. Compliance with Renewable Biomass Provision

EISA changed the definition of "renewable fuel" to require that it be made from feedstocks that qualify as "renewable biomass." EISA's definition of the term "renewable biomass" limits the types of biomass as well as the types of land from which the biomass may be harvested. The definition includes:

- Planted crops and crop residue from agricultural land cleared prior to December 19, 2007 and actively managed or fallow on that date
- Planted trees and tree residue from tree plantations cleared prior to December 19, 2007 and actively managed on that date
- Animal waste material and byproducts
- Slash and pre-commercial thinnings from non-federal forestlands that are neither old-growth nor listed as critically imperiled or rare by a State Natural Heritage program
- Biomass cleared from the vicinity of buildings and other areas at risk of wildfire
- Algae
- Separated yard waste and food waste.

In today's rule, EPA is finalizing definitions for the many terms included within the definition of renewable biomass. Where possible, EPA has adhered to existing statutory, regulatory or industry definitions for these terms, although in some cases we have altered definitions to conform to EISA's statutory language, to further the goals of EISA, or for ease of program implementation. For example, EPA is defining "agricultural land" from which crops and crop residue can be harvested for RIN-generating renewable fuel production as including cropland, pastureland, and land enrolled in the Conservation Reserve Program. An in-depth discussion of the renewable biomass definitions can be found in Section II.B.4.

In keeping with EISA, under today's final rule, renewable fuel producers may only generate RINs for fuels made from feedstocks meeting the definition of renewable biomass. In order to implement this requirement, we are finalizing three potential mechanisms for domestic and foreign renewable fuel producers to verify that their feedstocks comply with this requirement. The first involves renewable biomass recordkeeping and reporting requirements by renewable fuel producers for their individual facilities. As an alternative to these individual recordkeeping and reporting requirements, the second allows renewable fuel producers to form a consortium to fund an independent third-party to conduct an annual renewable biomass quality-assurance survey, based on a plan approved by EPA. The third is an aggregate compliance approach applicable only to crops and crop residue from the U.S. It utilizes USDA's publicly available agricultural land data as the basis for an EPA determination of compliance with the renewable biomass requirements for these particular feedstocks. This determination will be reviewed annually, and if EPA finds it is no longer warranted, then renewable fuel producers using domestically grown crops and crop residue will be required to conduct individual or consortium-based verification processes to ensure that their feedstocks qualify as renewable biomass. These final provisions are described below, with a more in-depth discussion in Section II.B.4.

For renewable fuel producers using feedstocks other than planted crops or crop residue from agricultural land that do not choose to participate in the third-party survey funded by an industry consortium, the final renewable biomass recordkeeping and reporting provisions require that individual producers obtain documentation about their feedstocks from their feedstock supplier(s) and take the measures necessary to ensure that they know the source of their feedstocks and can demonstrate to EPA that they have complied with the EISA definition of renewable biomass. Specifically, EPA's renewable biomass reporting requirements for producers who generate RINs include a certification on renewable fuel production reports that the feedstock used for each renewable fuel batch meets the definition of renewable biomass. Additionally, producers will be required to include with their quarterly reports a summary of the types and volumes of feedstocks used throughout the quarter, as well as maps of the land from which the feedstocks used in the quarter were harvested. EPA's final renewable biomass recordkeeping provisions require renewable fuel producers to maintain sufficient records to support their claims that their feedstocks meet the definition of renewable biomass, including maps or electronic data identifying the boundaries of the land where the feedstocks were produced, documents tracing the feedstocks from the land to the renewable fuel production facility, other written records from their feedstock suppliers that serve as evidence that the feedstock qualifies as renewable biomass, and for producers using planted trees or tree residue from tree plantations, written records that serve as evidence that the land from which the feedstocks were obtained was cleared prior to December 19, 2007 and actively managed on that date.

Based on USDA's publicly available agricultural land data, EPA is able to establish a baseline of the aggregate amount of U.S. agricultural land (meaning cropland, pastureland and CRP land in the United States) that is available for the production of crops and crop residues for use in renewable fuel production consistent with the definition of renewable biomass. EPA has determined that, in the aggregate this amount of agricultural land (land cleared or cultivated prior to EISA's enactment (December 19, 2007) and actively managed or fallow, and nonforested on that date) is expected to, at least in the near term, be sufficient to support EISA renewable fuel obligations and other foreseeable demands for crop products, without clearing and cultivating additional land. EPA also believes that economic factors will lead farmers to use the "agricultural land" available for crop production under EISA rather than bring new land into crop production. As a result, EPA is deeming renewable fuel producers using domestically-grown crops and crop residue as feedstock to be in compliance with the renewable biomass requirements, and those producers need not comply with the recordkeeping and quarterly reporting requirements as established for the non–crop based biomass sector. However, EPA will annually review USDA data on lands in agricultural production to determine if these conclusions remain valid. If EPA determines that the 2007 baseline amount of eligible agricultural land has been exceeded, EPA will publish a notice of that finding in the Federal Register. At that point, renewable fuel producers using planted crops or crop residue from agricultural lands would be subject to the same recordkeeping and reporting requirements as other renewable fuel producers.

5. EPA-Moderated Transaction System

We introduced the EPA Moderated Transaction System (EMTS) in the NPRM as a new method for managing the generation of RINs and transactions involving RINs. EMTS is designed to resolve the RIN management issues of RFS1 that lead to widespread RIN errors, many times resulting in invalid RINs and often tedious remedial procedures to resolve those errors. It is also designed to address the added RIN categories, more complex RIN generation requirements, and additional volume of RINs associated with RFS2. Commenters broadly support EMTS and most stated that its use should coincide with the start of RFS2; however, many commenters expressed concerns over having sufficient time to implement the new system. In today's action, we are requiring the use of EMTS for all RFS2 RIN generations and transactions beginning July 1, 2010. EPA has utilized an open process for the development of EMTS since it was first introduced in the NPRM, conducting workshops and webinars, and soliciting stakeholder participation in its evaluation and testing. EPA pledges to work with the regulated community, as a group and individually, to ensure EMTS is successfully implemented. EPA anticipates that with this level of assistance, regulated parties will not experience significant difficulties in transitioning to the new system, and EPA believes that the many benefits of the new system warrant its immediate use.

6. Other Changes to the RFS Program

Today's final rule also makes a number of other changes to the RFS program that are described in more detail in Sections II and III below, including:

- Grandfathering provisions: Renewable fuel from existing facilities is exempt from the lifecycle GHG emission reduction threshold of 20% up to a baseline volume for that facility that will be established at the time of registration. As discussed in Section II.B.3, the exemption from the 20% GHG threshold applies only to renewable fuel that is produced from facilities which commenced construction on or before December 19, 2007, or in the case of ethanol plants that use natural gas or biodiesel for process heat, on or before December 31, 2009.

- Renewable fuels produced from municipal solid waste (MSW): The new renewable biomass definition in EISA modified the ability for MSW-derived fuels to qualify under the RFS program by restricting it to "separated yard waste or food waste." We are finalizing provisions that would allow certain portions of MSW to be included as renewable biomass, provided that reasonable separation has first occurred.

- Equivalence Values: We are generally maintaining the provisions from RFS1 that the Equivalence Value for each renewable fuel will be based on its energy content in comparison to ethanol, adjusted for renewable content. The cellulosic biofuel, advanced biofuel, and renewable fuel standards can be met with ethanol-equivalent volumes of renewable fuel. However, since the biomass-based diesel standard is a "diesel" standard, its volume must be met on a biodiesel-equivalent energy basis.

- Cellulosic biofuel waiver credits: If EPA reduces the required volume of cellulosic biofuel according to the waiver provisions in EISA, EPA will offer a number of credits to obligated parties no greater than the reduced cellulosic biofuel standard. These waiver credits are not allowed to be traded or banked for future use, and are only allowed to be used to meet the cellulosic biofuel standard for the year that they are offered. In response to concerns expressed in comments on the proposal, we are implementing certain restrictions on the use of these waiver credits. For example, unlike Cellulosic Biofuel RINs, waiver credits may not be used to meet either the advanced biofuel standard or the total renewable fuel standard. For the 2010 compliance period, since the cellulosic standard is lower than the level otherwise required by EISA, we are making cellulosic waiver credits available to obligated parties for end-of-year compliance should they need them at a price of $1.56 per gallon-RIN.

- Obligated fuels: EISA expanded the program to cover "transportation fuel", not just gasoline. Therefore, under RFS2, obligated fuel volumes will include all gasoline and all MVNRLM diesel fuel. Other fuels such as jet fuel and fuel intended for use in ocean-going vessels are not obligated fuels under RFS2. However, renewable fuels used in jet fuel or heating oil are valid for meeting the renewable fuel volume mandates. Similarly, while we are not including natural gas, propane or electricity used in transportation as obligated fuels at this time, we will allow renewable forms of these fuels to qualify under the program for generating RINs.

B. Impacts of Increasing Volume Requirements in the RFS2 Program

The displacement of gasoline and diesel with renewable fuels has a wide range of environmental and economic impacts. As we describe in Sections IV-IX, we have assessed many of these impacts for the final rule. It is difficult to ascertain how much of these impacts might be due to the natural growth in renewable fuel use due to market forces as crude oil prices rise versus what might be forced by the RFS2 standards. Regardless, these assessments provide important information on the wider public policy considerations related to renewable fuel production and use, climate change, and national energy security. Where possible, we have tried to provide two perspectives on the impacts of the renewable fuel volumes mandated in EISA – both relative to the RFS1 mandated volumes, and relative to a projection from EIA (AEO 2007) of renewable fuel volumes that would have been expected without EISA.

Based on the results of our analyses, when fully phased in by 2022, the increased volume of renewable fuel required by this final rule in comparison to the AEO 2007 forecast would result in 138 million metric tons fewer CO_2-equivalent GHG emissions (annual average over 30 years), the equivalent of removing 27 million vehicles from the road today.

At the same time, increases in emissions of hydrocarbons, nitrogen oxides, particulate matter, and other pollutants are projected to lead to increases in population-weighted annual average ambient PM and ozone concentrations, which in turn are anticipated to lead to up to 245 cases of adult premature mortality. The air quality impacts, however, are highly variable from region to region. Ambient $PM_{2.5}$ is likely to increase in areas associated with biofuel production and transport and decrease in other areas; for ozone, many areas of the country will experience increases and a few areas will see decreases. Ethanol concentrations will increase substantially; for the other modeled air toxics there are some localized impacts, but relatively little impact on national average concentrations. We note that the air quality modeling results presented in this final rule do not constitute the "anti-backsliding" analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action.

In addition to air quality, there are also expected to be adverse impacts on both water quality and quantity as the production of biofuels and their feedstocks increase.

In addition to environmental impacts, the increased volumes of renewable fuels required by this final rule are also projected to have a number of other energy and economic impacts. The increased renewable fuel use is estimated to reduce dependence on foreign sources of crude oil, increase domestic sources of energy, and diversify our energy portfolio to help in moving beyond a petroleum-based economy. The increased use of renewable fuels is also expected to have the added benefit of providing an expanded market for agricultural products such as corn and soybeans and open new markets for the development of cellulosic feedstock industries and conversion technologies. Overall, however, we estimate that the renewable fuel standards will result in significant net benefits, ranging between $16 and $29 billion in 2022.

Table I.B-1 summarizes the results of our impacts analyses of the volumes of renewable fuels required by the RFS2 standards in 2022 relative to the AEO2007 reference case and identifies the section where you can find further explanation of it. As we work to implement the requirements of EISA, we will continue to assess these impacts. These are the annual impacts projected in 2022 when the program is fully phased in. Impacts in earlier years would differ but in most cases were not able to be modeled or assessed for this final rule.

Table I.B-1
Impact Summary of the RFS2 Standards in 2022 Relative to the AEO2007 Reference Case (2007 Dollars)

Category	Impact in 2022	Section Discussed
Emissions and Air Quality		
GHG Emissions	-138 million metric tons	V.D.
Non-GHG Emissions (criteria and toxic pollutants)	-1% to +10% depending on the pollutant	VI.A.
Nationwide Ozone	+0.12 ppb population-weighted seasonal max 8hr average	VIII.D.
Nationwide $PM_{2.5}$	+0.002 $\mu g/m^3$ population-weighted annual average $PM_{2.5}$	VIII.D.
Nationwide Ethanol	+0.409 $\mu g/m^3$ population-weighted annual average	VI.D.
Other Nationwide Air Toxics	-0.0001 to -0.023 $\mu g/m^3$ population-weighted annual average depending on the pollutant	VI.D.
$PM_{2.5}$-related Premature Mortality	33 to 85 additional cases of adult mortality (estimates vary by study)	VIII.D.
Ozone-related Premature Mortality	36 to 160 additional cases of adult mortality (estimates vary by study)	VIII.D.
Other Environmental Impacts		
Loadings to the Mississippi River from the Upper Mississippi River Basin	Nitrogen: +1,430 million lbs. (1.2%) Phosphorus: +132 million lbs. (0.7%)	IX
Fuel Costs		
Gasoline Costs	-2.4¢/gal	VII.D.
Diesel Costs	-12.1 ¢/gal	VII.D.
Overall Fuel Cost	-$11.8 Billion	VII.D.
Gasoline and Diesel Consumption	- 13.6 Bgal	VII.C.
Food Costs		
Corn	+8.2%	VIII.A.
Soybeans	+10.3%	VIII.A.
Food	+$10 per capita	VIII.A.
Economic Impacts		
Energy Security	+$2.6 Billion	VIII.B.
Monetized Health Impacts	-$0.63 to -$2.2 Billion	VIII.D.

GHG Impacts (SCC)[a]	+$0.6 to $12.2 Billion (estimates vary by SCC assumption)	VIII.C.
Oil Imports	-$41.5 Billion	VIII.B
Farm Gate Food	+$3.6 Billion	VIII.A.
Farm Income	+$13 Billion (+36%)	VIII.A.
Corn Exports	-$57 Million (-8%)	VIII.A.
Soybean Exports	-$453 Million (-14%)	VIII.A
Total Net Benefits[b]	+$13 to $26 Billion (estimates vary by SCC assumption)	VIII.F

[a] The models used to estimate SCC values have not been exercised in a systematic manner that would allow researchers to assess the probability of different values. Therefore, the interim SCC values should not be considered to form a range or distribution of possible or likely values. See Section VIII.D for a complete summary of the interim SCC values.

[b] Sum of Overall Fuel Costs, Energy Security, Monetized Health Impacts, and GHG Impacts (SCC).

II. Description of the Regulatory Provisions

While EISA made a number of changes to CAA section 211(o) that must be reflected in the RFS program regulations, it left many of the basic program elements intact, including the mechanism for translating national renewable fuel volume requirements into applicable standards for individual obligated parties, requirements for a credit trading program, geographic applicability, treatment of small refineries, and general waiver provisions. As a result, many of the regulatory requirements of the RFS1 program will remain largely or, in some cases, entirely unchanged. These provisions include the distribution of RINs, separation of RINs, use of RINs to demonstrate compliance, provisions for exporters, recordkeeping and reporting, deficit carryovers, and the valid life of RINs.

The primary elements of the RFS program that we are changing to implement the requirements in EISA fall primarily into the following seven areas:

1) Expansion of the applicable volumes of renewable fuel

2) Separation of the volume requirements into four separate categories of renewable fuel, with corresponding changes to the RIN and to the applicable standards

3) New definitions of renewable fuel, advanced biofuel, biomass-based diesel, and cellulosic biofuel.

4) New requirement that renewable fuels meet certain lifecycle emission reduction thresholds.

5) New definition of renewable biomass from which renewable fuels can be made, including certain land use restrictions.

6) Expansion of the types of fuels that are subject to the standards to include diesel.

7) Inclusion of specific types of waivers for different categories of renewable fuels and, in certain circumstances, EPA-generated credits for cellulosic biofuel.

EISA does not change the basic requirement under CAA 211(o) that the RFS program include a credit trading program. In the May 1, 2007 final rulemaking implementing the RFS1 program, we described how we reviewed a variety of approaches to program design in collaboration with various stakeholders. We finally settled on a RIN-based system for compliance and credit purposes as the one which met our goals of being straightforward, maximizing flexibility, ensuring that volumes are verifiable, and maintaining the existing system of fuel distribution and blending. RINs represent the basic framework for ensuring that the statutorily required volumes of renewable fuel are used as transportation fuel in the U.S. Since the RIN-based system generally has been successful in meeting the statutory goals, we are maintaining much of its structure under RFS2.

This section describes the regulatory changes we are finalizing to implement the new EISA provisions. Section III describes other changes to the RFS program that we considered or are finalizing, including an EPA-moderated RIN trading system that provides a context within which all RIN transfers will occur.

A. Renewable Identification Numbers (RINs)

Under RFS2, each RIN will continue to represent one gallon of renewable fuel in the context of demonstrating compliance with Renewable Volume Obligations (RVO), consistent with our approach under RFS1, and the RIN will continue to have unique information similar to the 38 digits in RFS1. However in the EPA Moderated Transaction System (EMTS), RIN detail information will be available but generally hidden during transactions. In general the codes within the RIN will have the same meaning under RFS2 as they do under RFS1, with the exception of the D code which will be expanded to cover the four categories of renewable fuel defined in EISA.

As described in Section I.A.2, the RFS2 regulatory program will go into effect on July 1, 2010, but the 2010 percentage standards issued as part of today's rule will apply to all gasoline and diesel produced or imported on or after January 1, 2010. As a result, some 2010 RINs will be generated under the RFS1 requirements and others will be generated under the RFS2 requirements, but all RINs generated in 2010 will be valid for meeting the 2010 annual standards. Since RFS1 RINs and RFS2 RINs will differ in the meaning of the D codes, we are implementing a mechanism for distinguishing between these two categories of RINs in order to appropriately apply them to the standards. In short, we are requiring the use of D codes under RFS2 that do not overlap the values for the D codes under RFS1. Table II.A-1 describes the D code definitions we are finalizing in today's action.

Table II.A-1
Final D Code Definitions

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Not applicable
2	Any renewable fuel that is not cellulosic biomass ethanol	Not applicable
3	Not applicable	Cellulosic biofuel
4	Not applicable	Biomass-based diesel
5	Not applicable	Advanced biofuel
6	Not applicable	Renewable fuel
7	Not applicable	Cellulosic diesel

Under this approach, D code values of 1 and 2 are only relevant for RINs generated under RFS1, and D code values of 3, 4, 5, 6, and 7 are only relevant for RINs generated under RFS2. As described in Section I.A.2, the RFS1 regulations will apply in January through June of 2010, while the RFS2 regulations will become effective on July 1, 2010. RINs generated under RFS1 regulations in the first three months of 2010 can be used for meeting the four 2010 standards applicable under RFS2. To accomplish this, these RFS1 RINs will be subject to the RFS1/RFS2 transition provisions wherein they will be deemed equivalent to one of the four RFS2 RIN categories using their RR and/or D codes. See Section II.G.4 for further description of how RFS1 RINs will be used to meet standards under RFS2. The determination of which D code will be assigned to a given batch of renewable fuel is described in more detail in Section II.D.2 below.

Table II.A-1 includes one D code corresponding to each of the four renewable fuel categories defined in EISA, and an additional D code of 7 corresponding to the unique, additional type of renewable fuel called cellulosic diesel. As described in the NPRM, a diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold could qualify as either cellulosic biofuel or biomass-based diesel. The NPRM described two possible approaches to this unique category of renewable fuel:

1. Have the producer of the cellulosic diesel designate their fuel up front as either cellulosic biofuel with a D code of 3, or biomass-based diesel with a D code of 4, limiting the subsequent potential in the marketplace for the RIN to be used for just one standard or the other.

2. Have the producer of the cellulosic diesel designate their fuel with a new cellulosic D code of 7, allowing the subsequent use of the RIN in the marketplace interchangeably for either the cellulosic biofuel standard or the biomass-based diesel standard.

We are finalizing the second option. By creating an additional D code of 7 to represent cellulosic diesel RINs, we believe its value in the marketplace will be maximized as it will be priced according to the relative demand for cellulosic biofuel and biomass-based diesel RINs. For instance, if demand for cellulosic biofuel RINs is higher than demand for biomass-based diesel RINs, then cellulosic diesel RINs will be priced as if they are cellulosic biofuel RINs. Not only does this approach benefit producers, but it allows obligated parties the flexibility to apply a RIN with a D code of 7 to either their cellulosic biofuel RVO or their biomass-based diesel RVO, depending on the number of RINs they have acquired to meet these two obligations. It also helps the functionality of the RIN program by helping protect against the potential for artificial RIN shortages in the marketplace for one standard or the other even though sufficient qualifying fuel was produced.

Under RFS2, each batch-RIN generated will continue to uniquely identify not only a specific batch of renewable fuel, but also every gallon-RIN assigned to that batch. Thus the RIN will continue to be defined as follows:

RIN: KYYYYCCCCFFFFFBBBBBRRDSSSSSSSSEEEEEEEE

Where

K	= Code distinguishing assigned RINs from separated RINs
YYYY	= Calendar year of production or import
CCCC	= Company ID
FFFFF	= Facility ID

BBBBB	= Batch number
RR	= Code identifying the Equivalence Value
D	= Code identifying the renewable fuel category
SSSSSSSS	= Start of RIN block
EEEEEEEE	= End of RIN block

B. New Eligibility Requirements for Renewable Fuels

Aside from the higher volume requirements, most of the substantive changes that EISA makes to the RFS program affect the eligibility of renewable fuels in meeting one of the four volume requirements. Eligibility is determined based on the types of feedstocks that are used, the land that is used to grow feedstocks for renewable fuel production, the processes that are used to convert those feedstocks into fuel, and the lifecycle greenhouse gas (GHG) emissions that are emitted in comparison to the gasoline or diesel that the renewable fuel displaces. This section describes these eligibility criteria and how we are implementing them for the RFS2 program.

1. Changes in Renewable Fuel Definitions

Under the previous Renewable Fuel Standards (RFS1), renewable fuel was defined generally as "any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle". The RFS1 definition included motor vehicle fuels produced from biomass material such as grain, starch, fats, greases, oils, and biogas. The definition specifically included cellulosic biomass ethanol, waste derived ethanol, and biodiesel, all of which were defined separately. (See 72 FR 23915).

The definitions of renewable fuels under today's rule (RFS2) are based on the new statutory definition in EISA. Like the previous rules, the definitions in RFS2 include a general definition of renewable fuel, but unlike RFS1, we are including a separate definition of "Renewable Biomass" which identifies the feedstocks from which renewable fuels may be made.

Another difference in the definitions of renewable fuel is that RFS2 contains three subcategories of renewable fuels: 1) Advanced Biofuel, 2) Cellulosic Biofuel and 3) Biomass-Based Diesel. Each must meet threshold levels of reduction of greenhouse gas emissions as discussed in Section II.B.2. The specific definitions and how they differ from RFS1 follow below.

a. Renewable Fuel

"Renewable Fuel" is defined as fuel produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel. The definition of "Renewable Fuel" now refers to "transportation fuel" rather than referring to motor vehicle fuel. "Transportation fuel" is also defined, and means fuel used in motor vehicles, motor vehicle engines, nonroad vehicles or nonroad engines (except for ocean going vessels). Also renewable fuel now includes heating fuel and jet fuel.

Given that the primary use of electricity, natural gas, and propane is not for fueling vehicles and engines, and the producer generally does not know how it will be used, we cannot require that producers or importers of these fuels generate RINs for all the volumes they produce as we do with other renewable fuels. However, we are allowing fuel producers, importers and end users to include electricity, natural gas, and propane made from renewable biomass as a RIN-generating renewable fuel in RFS only if they can identify the specific quantities of their product which are actually used as a transportation fuel,. This may be possible for some portion of renewable electricity and biogas since many of the affected vehicles and equipment are in centrally-fueled fleets supplied under contract by a particular producer or importer of natural gas or propane. A producer or importer of renewable electricity or biogas who documents the use of his product in a vehicle or engine through a contractual pathway would be allowed to generate RINs to represent that product, if it met the definition of renewable fuel. (This is also discussed in Section II.D.2.a)

b. Advanced Biofuel

"Advanced Biofuel" is a renewable fuel other than ethanol derived from corn starch and for which lifecycle GHG emissions are at least 50% less than the gasoline or diesel fuel it displaces. Advanced biofuel would be assigned a D code of 5 as shown in Table II.A-1.

While "Advanced Biofuel" specifically excludes ethanol derived from corn starch, it includes other types of ethanol derived from renewable biomass, including ethanol made from cellulose, hemicellulose, lignin, sugar or any starch other than corn starch, as long as it meets the 50% GHG emission reduction threshold. Thus, even if corn starch-derived ethanol were made so that it met the 50% GHG reduction threshold, it will still be excluded from being defined as an advanced biofuel. Such ethanol while not an advanced biofuel will still qualify as a renewable fuel for purposes of meeting the standards.

c. Cellulosic Biofuel

Cellulosic biofuel is renewable fuel derived from any cellulose, hemicellulose, or lignin each of which must originate from renewable biomass. It must also achieve a lifecycle GHG emission reduction of at least 60%, compared to the gasoline or diesel fuel it displaces. Cellulosic biofuel is assigned a D code of 3 as shown in Table II.A-1. Cellulosic biofuel in general also qualifies as both "advanced biofuel" and "renewable fuel".

The definition of cellulosic biofuel for RFS2 is broader in some respects than the RFS1 definition of "cellulosic biomass ethanol". That definition included only ethanol, whereas the RFS2 definition of cellulosic biofuels includes any biomass-to-liquid fuel such as cellulosic gasoline or diesel in addition to ethanol. The definition of "cellulosic biofuel" in RFS2 differs from RFS1 in another significant way. The RFS1 definition provided that ethanol made at any facility—regardless of whether cellulosic feedstock is used or not—may be defined as cellulosic if at such facility "animal wastes or other waste materials are digested or otherwise used to displace 90% or more of the fossil fuel normally used in the production of ethanol." This provision was not included in EISA, and therefore does not appear in the definitions pertaining to cellulosic biofuel in the final rule.

d. Biomass-Based Diesel

"Biomass-based diesel" includes both biodiesel (mono-alkyl esters) and non-ester renewable diesel (including cellulosic diesel). The definition of biodiesel is the same very broad definition of "biodiesel" that was in EPAct and in RFS1, and thus, it includes any diesel fuel made from biomass feedstocks. However, EISA added three restrictions. First, EISA requires that such fuel be made from renewable biomass. Second, its lifecycle GHG emissions must be at least 50% less than the diesel fuel it displaces. Third, the statutory definition of "Biomass-based diesel" excludes renewable fuel derived from co-processing biomass with a petroleum feedstock. In our proposed rule, we sought comment on two options for how co-processing could be treated. The first option considered co-processing to occur only if both petroleum and biomass feedstock are processed in the same unit simultaneously. The second option considered co-processing to occur if renewable biomass and petroleum feedstock are processed in the same unit at any time; i.e., either simultaneously or sequentially. Under the second option, if petroleum feedstock was processed in the unit, then no fuel produced from such unit, even from a biomass feedstock, would be deemed to be biomass-based diesel.

We selected the first option to be used in the final rule. Under this approach, a batch of fuel qualifying for the D code of 4 that is produced in a processing unit in which only renewable biomass is the feedstock for such batch, will meet the definition of "Biomass-Based Diesel. Thus, serial batch processing in which 100% vegetable oil is processed one day/week/month and 100% petroleum the next day/week/month could occur without the activity being considered "co-processing." The resulting products could be blended together, but only the volume produced from vegetable oil will count as biomass-based diesel. We believe this is the most straightforward approach and an appropriate one, given that it would allow RINs to be generated for volumes of fuel meeting the 50% GHG reduction threshold that is derived from renewable biomass, while not providing any credit for fuel derived from petroleum sources. In addition, this approach avoids the need for potentially complex provisions addressing how fuel should be treated when existing or even mothballed petroleum hydrotreating equipment is retrofitted and placed into new service for renewable fuel production or vice versa.

Under today's rule, any fuel that does not satisfy the definition of biomass-based diesel only because it is co-processed with petroleum will still meet the definition of "Advanced Biofuel" provided it meets the 50% GHG threshold and other criteria for the D code of 5. Similarly it will meet the definition of renewable fuel if it meets a GHG emission reduction threshold of 20%. In neither case, however, will it meet the definition of biomass-based diesel.

This restriction is only really an issue for renewable diesel and biodiesel produced via the fatty acid methyl ester (FAME) process. For other forms of biodiesel, it is never made through any sort of co-processing with petroleum[3]. Producers of renewable diesel must therefore specify

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[3] The production of biodiesel (mono alkyl esters) does require the addition of methanol which is usually derived from natural gas, but which contributes a very small amount to the resulting product. We do not believe that this

whether or not they use "co-processing" to produce the fuel in order to determine the correct D code for the RIN.

e. Additional Renewable Fuel

The statutory definition of "additional renewable fuel" specifies fuel produced from renewable biomass that is used to replace or reduce fossil fuels used in heating oil or jet fuel. EISA indicates that EPA may allow for the generation of credits for such additional renewable fuel that will be valid for compliance purposes. Under the RFS program, RINs operate in the role of credits, and RINs are generated when renewable fuel is produced rather than when it is blended. In most cases, however, renewable fuel producers do not know at the time of fuel production (and RIN generation) how their fuel will ultimately be used.

Under RFS1, only RINs assigned to renewable fuel that was blended into motor vehicle fuel (i.e., highway fuel) are valid for compliance purposes. We therefore created special provisions requiring that RINs be retired if they were assigned to renewable fuel that was ultimately blended into nonroad fuel. The new EISA provisions regarding additional renewable fuel make the RFS1 requirement for retiring RINs unnecessary if renewable fuel is blended into heating oil or jet fuel. As a result, we have modified the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel in addition to highway and nonroad transportation fuels to continue to be valid for compliance purposes. From a regulatory standpoint, there is no difference between renewable fuels used for transportation purposes, versus heating oil and jet fuels.

EISA uses the term “home heating oil” in the definition of “additional renewable fuel.” The statute does not clarify whether the term should be interpreted to refer only to heating oil actually used in homes, or to all fuel of a type that can be used in homes. We note that the term “home heating oil” is typically used in industry in the latter manner, to refer to a type of fuel, rather than a particular use of it, and the term is typically used interchangeably in industry with heating oil, heating fuel, home heating fuel, and other terms depending on the region and market. We believe this broad interpretation based on typical industry usage best serves the goals and purposes of the statute. If EPA interpreted the term to apply only to heating oil actually used in homes, we would necessarily require tracking of individual gallons from production through ultimate use in use in homes in order to determine eligibility of the fuel for RINs. Given the fungible nature of the oil delivery market, this would likely be sufficiently difficult and potentially expensive so as to discourage the generation of RINs for renewable fuels used as home heating oil. This problem would be similar to that which arose under RFS1 for certain renewable fuels (in particular biodiesel) that were produced for the highway diesel market but were also suitable for other markets such as heating oil and non-road applications where it was unclear at the time of fuel production (when RINs are typically generated under the RFS program) whether the fuel would ultimately be eligible to generate RINs. Congress eliminated the complexity with regards to non-road applications in RFS2 by making all fuels used in both motor vehicle and nonroad applications subject to the renewable fuel standard program. We believe it best to interpret the Act so as to also avoid this type of complexity in the heating oil

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was intended by the statute's reference to "co-processing" which we believe was intended to address only renewable fats or oils co-processed with petroleum in a hydrotreater to produce renewable diesel.

context. Thus, under today's regulations, RINs may be generated for renewable fuel used as "heating oil," as defined in existing EPA regulations at 80.2(ccc). In addition to simplifying implementation and administration of the Act, this interpretation will best realize the intent of EISA to reduce or replace the use of fossil fuels,

f. Cellulos ic Diesel

In the proposed rule, we sought comment on how diesel made from cellulosic feedstocks should be considered. Specifically, a diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold could qualify as either cellulosic biofuel or biomass-based diesel. Based on comments received, and as discussed previously in Section II.A, today's rule requires the cellulosic diesel producer to categorize their product as cellulosic diesel with a D code of 7. It can then be traded in the marketplace and used for compliance with either the biomass-based diesel standard or the cellulosic biofuel standard.

2. Lifecycle GHG Thresholds

As part of the new definitions that EISA creates for cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel, EISA also sets minimum performance measures or "thresholds" for lifecycle GHG emissions. These thresholds represent the percent reduction in lifecycle GHGs that is estimated to occur when a renewable fuel displaces gasoline or diesel fuel. Table II.B.2-1 lists the thresholds established by EISA.

Table II.B.2-1
Lifecycle GHG Thresholds in EISA
(percent reduction from a 2005 gasoline or diesel baseline)

Renewable fuel	20%
Advanced biofuel	50%
Biomass-based diesel	50%
Cellulosic biofuel	60%

There are also special provisions for each of these thresholds:

Renewable fuel: The 20% threshold only applies to renewable fuel from new facilities that commenced construction after December 19, 2007, with an additional exemption from the 20% threshold for ethanol plants that commenced construction in 2008 or 2009 and are fired with natural gas, biomass, or any combination thereof. Facilities not subject to the 20% threshold are "grandfathered." See Section II.B.3 below for a complete discussion of grandfathering. Also, EPA can adjust the 20% threshold to as low as 10%, but the adjustment must be the minimum possible, and the resulting threshold must be established at the maximum achievable level based on natural gas fired corn-based ethanol plants.

Advanced biofuel and biomass-based diesel: The 50% threshold can be adjusted to as low as 40%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments can be made only if it is determined that the 50% threshold is not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes.

Cellulosic biofuel: Similarly to advanced biofuel and biomass-based diesel, the 60% threshold applicable to cellulosic biofuel can be adjusted to as low as 50%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments can be made only if it is determined that the 60% threshold is not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes.

Our analyses of lifecycle GHG emissions, discussed in detail in Section V, identified a range of fuel pathways that are capable of complying with the GHG performance thresholds for each of these separate fuel standards. Thus, we have determined that the GHG thresholds in Table II.B.2-1 should not be adjusted. Further discussion of this determination can be found in Section V.C.

3. Renewable Fuel Exempt from 20 Percent GHG Threshold

After considering comments received, the Agency has decided to implement the proposed option for interpreting the grandfathering provisions that provide an indefinite exemption from the 20 percent GHG threshold for renewable fuel facilities which have commenced construction prior to December 19, 2007. For these facilities, only the baseline volume of renewable fuel is exempted. For ethanol facilities which commenced construction after that date and which use natural gas, biofuels or a combination thereof, we proposed that such facilities would be "deemed compliant" with the 20 percent GHG threshold. The exemption for such facilities is conditioned on construction being commenced on or before December 31, 2009, and is specific only to facilities which produce ethanol only, per language in EISA. The exemption would continue indefinitely, provided the facility continues to use natural gas and/or biofuel. This section provides the background and summary of the original proposal, and the reasons for the selection of this option.

a. General Background of the Exemption Requirement

EISA amends section 211(o) of the Clean Air Act to provide that renewable fuel produced from new facilities which commenced construction after December 19, 2007 must achieve at least a 20% reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions.[7] Facilities that commenced construction before December 19, 2007 are "grandfathered" and thereby exempt from the 20% GHG reduction requirement.

For facilities that produce ethanol and for which construction commenced after December 19, 2007, section 210 of EISA states that 'for calendar years 2008 and 2009, any ethanol plant that is fired with natural gas, biomass, or any combination thereof is deemed to be in compliance with the 20% threshold." Since all renewable fuel production facilities that commenced construction prior to the date of EISA enactment are covered by the more general grandfathering provision, this exemption can only apply to those facilities that commenced construction after enactment of EISA, and before the end of 2009. We proposed that the statute be interpreted to mean that fuel from such qualifying facilities, regardless of date of startup of operations, would be exempt from the 20% GHG threshold requirement for the same time period as facilities that commence construction prior to December 19, 2007, *provided* that such plants commence construction on or before December 31, 2009, complete such construction in a reasonable amount of time, and continue to burn only natural gas, biomass, or a combination thereof. Most commenters generally agreed with our proposal, while other commenters argued that the exemption was only meant to last for a two-year period. As we noted in the NPRM, we believe that it would be a harsh result for investors in these new facilities, and would be generally inconsistent with the energy independence goals of EISA, to interpret the Act such that these facilities would only be guaranteed two years of participation in the RFS2 program. In light of these considerations, we continue to believe that it is an appropriate interpretation of the Act to allow the deemed compliant exemption to continue indefinitely with the limitations we proposed. Therefore we are making final this interpretation in today's rule.

b. Definition of Commenced Construction

In defining "commence" and "construction", we proposed to use the definitions of "commence" and "begin actual construction" from the Prevention of Significant Deterioration (PSD) regulations, which draws upon definitions in the Clean Air Act. (40 CFR 52.21(b)(9) and (11)). Specifically, under the PSD regulations, "commence" means that the owner or operator has all necessary preconstruction approvals or permits and either has begun a continuous program of actual on-site construction to be completed in a reasonable time, or entered into binding agreements which cannot be cancelled or modified without substantial loss." Such activities include, but are not limited to, "installation of building supports and foundations, laying underground pipe work and construction of permanent storage structures." We proposed adding language to the definition that is currently not in the PSD definition with respect to multi-phased projects. We proposed that for multi-phased projects, commencement of construction of one phase does not constitute commencement of construction of any later phase, unless each phase is "mutually dependent" on the other on a physical and chemical basis, rather than economic.

The PSD regulations provide additional conditions beyond addressing what constitutes commencement. Specifically, the regulations require that the owner or operator "did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time." (40 CFR 52.21(i)(4)(ii)(c). While "reasonable time" may vary depending on the type of project, we proposed that for RFS2 a reasonable time to complete construction of renewable fuel facilities be no greater than 3 years from initial commencement of construction. We sought comment on this time frame.

Commenters generally agreed with our proposed definition of commenced construction. Some commenters felt that the 3 year time frame was not a 'reasonable time" to complete construction in light of the economic difficulties that businesses have been and will likely continue to be facing. We recognize that there have been extreme economic problems in the past year. Based on historical data which show construction of ethanol plants typically take about one year, we believe that the 3 year time frame allows such conditions to be taken into account and that it is an appropriate and fair amount of time to allow for completion Therefore, we are not extending the amount of time that constitutes “reasonable” to five years as was suggested.

c. Definition of Facility Boundary

We proposed that the grandfathering and deemed compliant exemptions apply to “facilities.”   Our proposed definition of this term is similar in some respects to the definition of “building, structure, facility, or installation” contained in the PSD regulations in 40 CFR 52.21. We proposed to modify the definition, however, to focus on the typical renewable fuel plant. We proposed to describe the exempt “facilities” as including all of the activities and equipment associated with the manufacture of renewable fuel which are located on one property and under the control of the same person or persons.   Commenters agreed with our proposed definition of “facility” and we are making that definition final today.

d. Proposed Approaches and Consideration of Comments

We proposed one basic approach to the exemption provisions and sought comment on five additional options. The basic approach would provide an indefinite extension of grandfathering and deemed compliant status but with a limitation of the exemption from the 20% GHG threshold to a baseline volume of renewable fuel. The five additional options for which we sought comment were: 1) Expiration of exemption for grandfathered and “deemed compliant” status when facilities undergo sufficient changes to be considered “reconstructed”; 2) Expiration of exemption 15 years after EISA enactment, industry-wide; 3) Expiration of exemption 15 years after EISA enactment with limitation of exemption to baseline volume; 4) “Significant” production components are treated as facilities and grandfathered or deemed compliant status ends when they are replaced; and 5) Indefinite exemption and no limitations placed on baseline volumes.

i. *Comments on the Proposed Basic Approach*

Generally, commenters supported the basic approach in which the volume of renewable fuel from grandfathered facilities exempt from the 20% GHG reduction threshold would be limited to baseline volume. One commenter objected to the basic approach and argued that the statute's use of the word "new" and the phrase "after December 19, 2007" provided evidence that facilities which commenced construction prior to that date would not ever be subject to the threshold regardless of the volume produced from such facilities.   In response, we note first that the statute does not provide a definition of the term "new facilities" for which the 20% GHG threshold applies. .   We believe that it would be reasonable to include within our interpretation of this term a volume limitation, such that a production plant is considered a new facility to the extent that it produces renewable fuel above baseline capacity. This approach also provides certainty in the marketplace in terms of the volumes of exempt fuel, and a relatively straightforward implementation and enforcement mechanism as compared to some of the other alternatives considered. Furthermore, EPA believes that the Act should not be interpreted as allowing unlimited expansion of exempt facilities for an indefinite time period, with all volumes exempt, as suggested by the commenter. Such an approach would likely lead to a substantial increase in production of fuel that is not subject to any GHG limitations, which EPA does not believe would be consistent with the objectives of the Act

We solicited comment on whether changes at a facility that resulted in an increase in GHG emissions, such as a change in fuel or feedstock, should terminate the facility's exemption from the 20 percent GHG threshold. Generally, commenters did not support such a provision, pointing out that there are many variations within a plant that cannot be adequately captured in a table of fuel and feedstock pathways as we proposed (see 74 FR 24927). Implementing such a provision would create questions of accounting and tracking that would need to be evaluated on a time-consuming case-by-case basis. For example, if a switch to a different feedstock or production process resulted in less efficiency, facilities may argue that they are increasing energy efficiency elsewhere (e.g. purchasing waste heat instead of burning fuel onsite to generate steam). We would then need to assess such changes to track the net energy change a plant undergoes. Given the added complexity and difficulty in carrying out such an option, we have decided generally not to implement it. There is an exception, however, for "deemed compliant" facilities. These facilities achieve their status in part by being fired only by natural gas or biomass, or a combination thereof. Today's rule provides, as proposed, that these facilities will lose their exemption if they switch to a fuel other than natural gas, biomass, or a combination thereof, since these were conditions that Congress deemed critical to granting them the exemption from the 20% GHG reduction requirement.

We also solicited comment on whether we should allow a 10% tolerance on the baseline volume for which RINs can be generated without complying with the 20% GHG reduction threshold to allow for increases in volume due to debottlenecking. Some favored this concept, while others argued that the tolerance should be set at 20 percent. After considering the comments received, we have decided that a 10% (and 20%) level is not appropriate for this regulation for the following reasons: 1) we have decided to interpret the exemption of the baseline volume of renewable fuel from the 20 percent requirement as extending indefinitely. Any tolerance provided could, therefore, be present in the marketplace for a considerable time period; 2) increases in volume of 10% or greater could be the result of modifications other than debottlenecking. Consistent with the basic approach we are taking today towards interpreting the grandfathering and deemed compliant provisions, we believe that the fuel produced as a result of such modifications comes from "new facilities" within the meaning of the statute, and should be subject to the 20% GHG reduction requirement; 3) we are allowing baseline volume to be based on the maximum capacity that is allowed under state and federal air permits. With respect to the last reason, facilities that have been operating below the capacity allowed in their state permits would be able to claim a baseline volume based on the maximum capacity. As such, these facilities may indeed be able to increase their volume by 10 to 20 percent by virtue of how their baseline volume is defined. We believe this is appropriate, however, since their permits should reflect their design, and the fuel resulting from their original pre-EISA (or pre-2010, for deemed compliant facilities) design should be exempt from the 20% GHG reduction requirement. Nevertheless, we recognize and agree with commenters that some allowances should be made for minor changes brought about by normal maintenance which are consistent with the proper operation of a facility. EPA is not aware of a particular study or analysis that could be used as a basis for picking a tolerance level reflecting this concept, We believe, however, that the value should be relatively small, so as not to encourage plant expansions that are unrelated to debottlenecking. We believe that a 5% tolerance level is consistent with these considerations, and have incorporated that value in today's rule.

ii. *Comments on the Expiration of Grandfathered Status*

Commenters who supported an expiration of the exemption did so because of concerns that the proposed approach of providing an indefinite exemption would not provide any incentives to bring these plants into compliance with current standards. They also objected to plants being allowed an indefinite period beyond the time period when it could be expected that they would have paid off their investors. The commenters argued that the cost of operation for such plants would be less than competing plants that do have to comply with current standards; as such, commenters opposed to the basic approach felt an indefinite exemption would be a subsidy to plants that will never comply with the 20 percent threshold level. The renewable fuels industry, on the other hand, viewed the options that would set an expiration date (either via cumulative reconstruction, or a 15 year period from date of enactment) as harsh, particularly if the lifecycle analysis results make it costly for existing facilities to meet the 20% threshold. Some also argued that no such temporal limitation appears in the statute.

We considered such comments, but in light of recent lifecycle analyses we conducted in support of this rule we have concluded that many of the current technology corn ethanol plants may find it difficult if not impossible to retrofit existing plants to comply with the 20 percent GHG reduction threshold. In addition, the renewable fuels industry viewed the alternative proposals that would set an expiration date (either via cumulative reconstruction, or a 15 year period from date of enactment) as harsh, particularly if the lifecycle analysis results make it costly for existing facilities to meet the 20% threshold. Given the difficulty of meeting such threshold, owners of such facilities could decide to shut down the plant. Given such implications of meeting the 20 percent threshold level for existing facilities we have chosen not to finalize any expiration date.

e. Final grandfathering provisions

For the reasons discussed above, the Agency has decided to proceed with the proposed baseline volume approach, rather than the expiration options. We hold open the possibility, therefore, of revisiting and reproposing the exemption provision in a future rulemaking to take such advances into account. Ending the grandfathering exemption after its usefulness is over would help to streamline the ongoing implementation of the program.

The final approach adopted today is summarized as follows:

i. *Increases in volume of renewable fuel produced at grandfathered facilities due to expansion*

For facilities that commenced construction prior to December 19, 2007, we are defining the baseline volume of renewable fuel exempt from the 20% GHG threshold requirement to be the maximum volumetric capacity of the facility that is allowed in any applicable state air permit or Federal Title V operating permit.[4] We had proposed in the NPRM that nameplate capacity be defined as permitted capacity, but that if the capacity was not stipulated in any federal, state or local air permit, then the actual peak output should be used. We have decided that since permitted capacity is the limiting condition, by virtue of it being an enforceable limit contained in air permits, that the term "nameplate capacity" is not needed. In addition, we are allowing a 5% tolerance as discussed earlier. Therefore, today's rule defines permitted capacity as 105% of the maximum permissible volume output of renewable fuel allowed under operating conditions specified in all applicable preconstruction, construction and operating permits issued by regulatory authorities (including local, regional, state or a foreign equivalent of a state, and federal permits) If the capacity of a facility is not stipulated in such air permits, then the grandfathered volume is 105% of the maximum annual volume produced for any of the last five calendar years prior to 2008. Volumes greater than this amount which may typically be due to expansions of the facility which occur after December 19, 2007, will be subject to the 20% GHG reduction requirement if the facility wishes to generate RINs for the incremental expanded volume. The increased volume will be considered as if produced from a "new facility" which commenced construction after December 19, 2007. Changes that might occur to the mix of renewable fuels produced within the facility are irrelevant—they remain grandfathered as long as the overall volume falls within the baseline volume. Thus, for example, if an ethanol facility changed its operation to produce butanol, but the baseline volume remained the same, the fuel so produced would be exempt from the 20% GHG reduction requirement.

The baseline volume will be defined as above for deemed compliant facilities (those ethanol facilities fired by natural gas or biomass or a combination thereof that commenced construction after December 19, 2007 but before January 1, 2010) with the exception that if the maximum capacity is not stipulated in air permits, then the exempt volume is the maximum annual peak production during the plant's first three years of operation. In addition, any production volume increase that is attributable to construction which commenced prior to December 31, 2009 would be exempt from the 20% GHG threshold, provided that the facility continued to use natural gas, biomass or a combination thereof for process energy. Because deemed compliant facilities owe their status to the fact that they use natural gas, biomass or a combination thereof for process heat, their status will be lost, and they will be subject to the 20% GHG threshold requirement, at any time that they change to a process energy source other than natural gas and/or biomass. Finally, because EISA limits deemed compliant facilities to ethanol facilities, if there are any changes in the mix of renewable fuels produced by the facility, only the ethanol volume remains grandfathered. We had solicited comment on whether fuels other than ethanol could also be deemed compliant. Based on comments received and additional consideration to this matter, we decided that because the Act does not authorize EPA to allow fuels other than ethanol, the deemed compliant provisions will apply only to facilities producing that fuel.

Volume limitations contained in air permits may be defined in terms of peak hourly production rates or a maximum annual capacity. If they are defined only as maximum hourly production rates, they will need to be converted to an annual rate. Because assumption of a 24-

[4] Volumes also include expansions to existing facilities, provided that the construction for such expansion commences prior to December 19, 2007. In such instances, the total volume from the original facility plus the additional volume due to expansion is grandfathered.

hour per day production over 365 days per year (8,760 production hours) may overstate the maximum annual capacity we are requiring a conversion rate of 95% of the total hours in a year (8,322 production hours) based on typical operating "uptime" of ethanol facilities.

The facility registration process (see Section II.C) will be used to define the baseline volume for individual facilities. Owners and operators must submit information substantiating the permitted capacity of the plant, or the maximum annual peak capacity if the maximum capacity is not stipulated in a federal, state or local air permit, or EPA Title V operating permit. Copies of applicable air permits which stipulate the maximum annual capacity of the plant, must be provided as part of the registration process. Subsequent expansions at a grandfathered facility that results in an increase in volume above the baseline volume will subject the increase in volume to the 20% GHG emission reduction threshold (but not the original baseline volume). Thus, any new expansions will need to be designed to achieve the 20% GHG reduction threshold if the facility wants to generate RINs for that volume. Such determinations will be made on the basis of EPA-defined fuel pathway categories that are deemed to represent such 20% reduction.

EPA enforcement personnel commented that claims for an exemption from the 20% GHG reduction requirement should be made promptly, so that they can be verified with recent supporting information. They were concerned, in particular, that claims for exempt status could be made many years into the future for facilities that may or may not have concluded construction within the required time period, but delayed actual production of renewable fuel due to market conditions or other reasons. EPA believes that this comment has merit, and has included a requirement in Section 80.1450(f) of the final rule for registration of facilities claiming an exemption from the 20% GHG reduction requirement by May 1, 2013. This provision does not require actual fuel production, but simply the filing of registration materials that assert a claim for exempt status. It will benefit both fuel producers, who will likely be able to more readily collect the required information if it is done promptly, and EPA enforcement personnel seeking to verify the information. However, given the potentially significant implications of this requirement for facilities that may qualify for the exemption but miss the registration deadline, the rule also provides that EPA may waive the requirement if it determines that the submission is verifiable to the same extent as a timely-submitted registration.

ii. *Replacements of equipment*

If production equipment such as boilers, conveyors, hoppers, storage tanks and other equipment are replaced, it would not be considered construction of a "new facility" under this option of today's final rule – the baseline volume of fuel would continue to be exempt from the 20% GHG threshold. We sought comment on an approach that would require that if coal-fired units are replaced, that the replacement units must be fired with natural gas or biofuel for the product to be eligible for RINs that do not satisfy the 20% GHG threshold. Some commenters supported such an approach. We agreed, however, with other commenters who point out that the language in EISA provides for an indefinite exemption for grandfathered facilities. While we interpret the statute to limit the exemption to the baseline volume of a grandfathered facility, we do not interpret the language to allow EPA to require that replacements of coal fired units be natural gas or biofuel. Thus replacements of coal fired equipment will not affect the facility's grandfathered status.

iii. *Registration, Recordkeeping and Reporting*

Facility owner/operators will be required to provide evidence and certification of commencement of construction. Such certification will require copies of all applicable air permits that apply to the construction and operation of the facility. Owner/operators must provide annual records of process fuels used on a BTU basis, feedstocks used and product volumes. For facilities that are located outside the United States (including outside the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands) owners will be required to provide certification as well. Since the definition of commencement of construction includes having all necessary air permits, we will require that facilities outside the United States certify that such facilities have obtained all necessary permits for construction and operation required by the appropriate national and local environmental agencies.

4. <u>New Renewable Biomass Definition and Land Restrictions</u>

As explained in Section I, EISA lists seven types of feedstock that qualify as "renewable biomass." EISA limits not only the types of feedstocks that can be used to make renewable fuel, but also the land that these renewable fuel feedstocks may come from. Specifically, EISA's definition of renewable biomass incorporates land restrictions for planted crops and crop residue, planted trees and tree residue, slash and pre-commercial thinnings, and biomass from wildfire areas. EISA prohibits the generation of RINs for renewable fuel made from feedstock that does not meet the definition of renewable biomass, which includes not meeting the associated land restrictions. The following sections describe EPA's interpretation of several key terms related to the definition of renewable biomass, and the approach in today's rule to implementing the renewable biomass requirements.

a. Definitions of Terms

EISA's renewable biomass definition includes a number of terms that require definition. The following sections discuss EPA's definitions for these terms, which were developed with ease of implementation and enforcement in mind. We have made every attempt to define these terms as consistently with other federal statutory and regulatory definitions as well as industry standards as possible, while keeping them workable for purposes of program implementation.

i. *Planted Crops and Crop Residue*

The first type of renewable biomass described in EISA is planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to December 19, 2007, that is either actively managed or fallow, and nonforested. We proposed to interpret the term "planted crops" to include all annual or perennial agricultural crops that may be used as feedstock for renewable fuel, such as grains, oilseeds, and sugarcane, as well as energy crops, such as switchgrass, prairie grass, and other species, providing that they were intentionally applied to the ground by humans either by direct application as seed or nursery stock, or through intentional natural seeding by mature plants left undisturbed for that purpose. We received numerous comments on our proposed definition of "planted crops," largely in support of our proposed definition. However, some commenters noted that "microcrops," such as duckweed, a flowering plant typically grown in ponds or tanks, are also being investigated for used as renewable fuel feedstocks. These microcrops are typically grown in a similar manner to algae, but cannot be categorized as algae since they are relatively more complex organisms. EPA's proposed definition would have unintentionally excluded microcrops such as duckweed through the requirement that planted crops be "applied to the ground." After considering comments received, EPA does not believe that there is any basis under EISA for excluding from the definition of renewable biomass crops such as duckweed that are applied to a tank or pond for growth rather than to the soil. As with other planted crops, these ponds or tanks must be located on existing "agricultural land," as described below, to qualify as renewable biomass under EISA. Therefore, including such microcrops within the definition of renewable biomass will not result in the direct loss of forestland or other ecologically sensitive land that Congress sought to protect through the land restrictions in the definition of renewable biomass. Doing so will further the objectives of the statute of promoting the development of emerging technologies to produce clean alternatives to petroleum-based fuels, and to further U.S. energy independence.

For these reasons, we are finalizing our proposed definition of "planted crops," with the inclusion of provisions allowing for the growth of "microcrops" in ponds or tanks that are located on agricultural land. Our final definition also includes a reference to "vegetative propagation," in which a new plant is produced from an existing vegetative structure, as one means by which planted crops may reproduce, since this is an important method of reproduction for microcrops such as duckweed. The final definition of "planted crops" includes all annual or perennial agricultural crops from existing agricultural land that may be used as feedstock for renewable fuel, such as grains, oilseeds, and sugarcane, as well as energy crops, such as switchgrass, prairie grass, duckweed and other species (but not including algae species or planted trees), providing that they were intentionally applied by humans to the ground, a growth medium, or a pond or tank, either by direct application as seed or plant, or through intentional natural seeding or vegetative propagation by mature plants introduced or left undisturbed for that purpose. We note that because EISA contains specific provisions for planted trees and tree residue from tree plantations, our final definition of planted crops in EISA excludes planted trees, even if they may be considered planted crops under some circumstances.

We proposed that "crop residue" be limited to the residue, such as corn stover and sugarcane bagasse, left over from the harvesting of planted crops. We sought comment on including biomass from agricultural land removed for purposes of invasive species control or fire management. We received many comments supporting the inclusion of biomass removed from agricultural land for purposes of invasive species control and/or fire management. We believe that such biomass is typically removed from agricultural land for the purpose of preserving or enhancing its value in agricultural crop production. It may be removed at the time crops are harvested, post harvest, periodically (e.g., for pastureland) or during extended fallow periods. We agree with the commenters that this material is a form of biomass residue related to crop production, whether or not derived from a crop itself, and, therefore, are modifying the proposed definition of "crop residue" to include it. We also received comments encouraging us to expand the definition of crop residue to include materials left over after the processing of the crop into a useable resource, such as husks, seeds, bagasse and roots. EPA agrees with these comments and has altered the final definition to cover such materials. Based on comments received, our final definition of "crop residue" is the biomass left over from the harvesting or processing of planted crops from existing agricultural land and any biomass removed from existing agricultural land that facilitates crop management (including biomass removed from such lands in relation to invasive species control or fire management), whether or not the biomass includes any portion of a crop or crop plant.

Our proposed regulations restricted planted crops and crop residue to that harvested from existing agricultural land, which, under our proposed definition, includes three land categories – cropland, pastureland, and Conservation Reserve Program (CRP) land. We proposed to define cropland as land used for the production of crops for harvest, including cultivated cropland for row crops or close-grown crops and non-cultivated cropland for horticultural crops. We proposed to define pastureland as land managed primarily for the production of indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types. We also proposed that CRP land, which is administered by USDA's Farm Service Agency, qualify as "agricultural land" under RFS2.

EPA received numerous comments on our proposed definition of existing agricultural land. Generally, commenters were in support of our definition of "cropland" and its inclusion in the definition of existing agricultural land. Additionally, commenters generally did not object to CRP lands or pastureland being included in the definition of agricultural land. Based on our consideration of comments received on the proposed rule, EPA is including cropland, pastureland and CRP land in the definition of existing agricultural land, as proposed.

We sought comment in the proposal on whether rangeland should be included as agricultural land under RFS2. Rangeland is land on which the indigenous or introduced vegetation is predominantly grasses, grass-like plants, forbs or shrubs and which – unlike cropland or pastureland – is predominantly managed as a natural ecosystem. EPA received a number of comments concerning whether rangeland should be included in the definition of existing agricultural land under RFS2. Some commenters urged EPA to expand the definition of existing agricultural land to include rangeland, arguing that rangelands could serve as important sources of renewable fuel feedstocks. Many of these commenters argued that, although it is generally less intensively managed than cropland, rangeland is nonetheless actively managed through control of brush or weed species, among other practices. In contrast, other commenters argued against the inclusion of rangeland, contending that the potential conversion of rangeland into cropland for growing renewable biomass would lead to losses of carbon, soil, water quality, and biodiversity.

Under EISA, renewable biomass includes crops and crop residue from agricultural land cleared or cultivated at any time prior to the enactment of EISA that is either "actively managed of fallow" and nonforested. In determining whether rangeland should be considered existing agricultural land under this provision, EPA must decide if rangeland qualifies as "actively managed or fallow." EPA believes that the term "actively managed" is best interpreted by reference to the type of material and practices that this provision addresses – namely crops and residue associated with growing crops. We think it is appropriate to inquire whether the type of management involved in a land type is consistent with that which would occur on land where crops are harvested. Thus, while we acknowledge that some types of rangeland are managed to a certain degree, the level of "active management" that is typically associated with land dedicated to growing agricultural crops is far more intensive than the types of management associated with rangeland. For example, rangeland is rarely tilled, fertilized or irrigated as croplands and, to a lesser degree, pasturelands, are. Furthermore, since rangeland encompasses a wide variety of ecosystems, including native grasslands or shrublands, savannas, wetlands, deserts and tundra, including it in the definition of agricultural land would increase the risk that these sensitive ecosystems would become available under EISA for conversion into intensively managed mono-culture cropland. Finally, the conversion of relatively undisturbed rangeland to the production of annual crops could in some cases lead to large releases of GHGs stored in the soil, as well as a loss of biodiversity, both of which would be contrary to EISA's stated goals. For these reasons, EPA is not including rangeland in the definition of "existing agricultural land" in today's final rule.

We proposed to include in our definition of existing agricultural land the requirement that the land was cleared or cultivated prior to December 19, 2007, and that, since December 19, 2007, it has been continuously actively managed (as agricultural land) or fallow, and nonforested. We proposed to interpret the phrase "that is actively managed or fallow, and nonforested" as meaning that land must have been actively managed or fallow, and nonforested, on December 19, 2007, and continuously thereafter in order to qualify for renewable biomass production. We received extensive comments on this interpretation. Many commenters suggested an interpretation of the requirement that agricultural land be "actively managed" to mean that the land had to be "actively managed" at the time EISA was passed on December 17, 2007, such that the amount of land available for biofuel feedstock production was established at that point and would not diminish over time. Other commenters supported our proposed interpretation, which would mean that the amount of land available for biofuel feedstock production could diminish over time if parcels of land cease to be actively managed at any point, thus taking them out of contention for biofuel feedstock cultivation. Some commenters argued that this interpretation is contrary to Congress' intent and the basic premise of the RFS program since, over time, it could lead to a reduction in the amount of renewable biomass available for use as renewable fuel feedstocks, while the statutorily required volumes of renewable fuel increase over time. These commenters further argue that the active management provision should be interpreted as a "snapshot" of agricultural land existing and actively managed on December 19, 2007. Under this interpretation, the land that was cleared or cultivated prior to December 19, 2007 and was actively managed on that date, would be eligible for renewable biomass production indefinitely.

We agree that that the goal of the EISA and RFS program, to increase the presence of renewable fuels in transportation fuel, will be better served by interpreting the "actively managed or fallow" requirement in the renewable biomass definition as applying to land actively managed or fallow on December 19, 2007, rather than interpreting this requirement as applying beginning on December 19, 2007 and continuously thereafter. In addition, by simplifying the requirement in this fashion, there will be significantly less burden on regulated parties in ensuring that their feedstocks come from qualifying lands. For these reasons, we are modifying the definition of existing agricultural land so that the “active management” requirement is satisfied for those that were cleared or cultivated and actively managed or fallow, and non-forested on December 19, 2007.

Further, we proposed and are finalizing that “actively managed” means managed for a predetermined outcome as evidenced by any of the following: sales records for planted crops, crop residue, or livestock; purchasing records for land treatments such as fertilizer, weed control, or reseeding; a written management plan for agricultural purposes; documentation of participation in an agricultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural certification program. While we received comments indicating that including a definitive checklist of required evidential records would be helpful to have explicitly identified in the regulations, we are not doing so in order to maintain flexibility, as feedstock producers may vary in the types of evidence they can readily obtain to show that their agricultural land was actively managed. We are adding, however, a clarification that the records must be traceable to the land in question. For example, it will not be sufficient to have a receipt for seed purchase if there is not additional evidence indicating that the seed was applied to the land which is claimed as existing agricultural land.

The term “fallow” is generally used to describe cultivated land taken out of production for a finite period of time. We proposed and sought comment on defining fallow to mean agricultural land that is intentionally left idle to regenerate for future agricultural purposes, with no seeding or planting, harvesting, mowing, or treatment during the fallow period. We also proposed and sought comment on requiring documentation of such intent. We received many comments that supported our proposed definition of fallow. We also received comments indicating that EPA should set a time limit for land to qualify as fallow (as opposed to abandoned for agricultural purposes). We have decided not to include a time limit for land to qualify as “fallow” because we understand that agricultural land may be left fallow for many different purposes and for varying amounts of time. Any particular timeframe that EPA might choose for this purpose would be somewhat arbitrary. Further, EISA does not indicate a time limit on the period of time that qualifying land could be fallow, so EPA does not believe that it would be appropriate to do so in its regulations. Therefore, EPA is finalizing its proposed definition of “fallow.”

Finally, in order to define the term “nonforested” as used in the definition of “existing agricultural land,” we proposed first to define the term “forestland” as generally undeveloped land covering a minimum area of one acre upon which the predominant vegetative cover is trees, including land that formerly had such tree cover and that will be regenerated. We also proposed that forestland would not include tree plantations. “Nonforested” land under our proposal would be land that is not forestland.

We received many comments on our proposed definition of forestland. Some commenters urged EPA to broaden the definition of “forestland” to include tree plantations, arguing that plantations are well-accepted as a subset of forestland. Others advocated that EPA should make every effort to distinguish between tree plantations and forestland so as not to run the risk of allowing native forests to be converted into less diverse tree plantations from which trees could be harvested for renewable fuel production. For today's final rule, EPA is including tree plantations as a subset of forestland since it is commonly understood as such throughout the forestry industry. Under EISA, renewable biomass may include "slash and pre-commercial thinnings" from non-federal forestlands, and "planted trees and tree residue" from actively managed tree plantations on non-federal land. One effect under EISA of the modification from the proposed rule to include tree plantations as a subset of forestland is to allow pre-commercial thinnings and slash, in addition to planted trees and tree residue, harvested from tree plantations to serve as qualifying feedstocks for renewable fuel production. EPA believes it is appropriate to include pre-commercial thinnings and slash from actively managed tree plantations as renewable biomass, consistent with the EISA provision allowing harvested trees and tree residue from tree plantations to qualify as renewable biomass. Another effect of including the tree plantations as a kind of forestland is that, since crops and crop residue must come from land that was "non-forested" as of the date of EISA enactment, a tract of land managed as a tree plantation on the date of EISA enactment could not be converted to cropland for the production of feedstock for RIN-generating renewable fuel. EPA believes that this result in keeping with Congressional desire to avoid the conversion of new lands to crop production for renewable fuel production.

Additionally, EPA received comments indicating that, in order to be consistent with existing statutory and/or regulatory definitions of "forestland," EPA should exclude tree covered areas in intensive agricultural crop production settings, such as fruit orchards, or tree-covered areas in urban settings such as city parks from the definition of forestland. EPA agrees that these types of land cannot be characterized as "forestland," and is thus excluding them from the definition. EPA's final definition of forestland is "generally undeveloped land covering a minimum of 1 acre upon which the primary vegetative species is trees, including land that formerly had such tree cover and that will be regenerated and tree plantations. Tree covered areas in intensive agricultural crop production settings, such as fruit orchards, or tree-covered areas in urban settings such as city parks, are not considered forestland."

ii. *Planted Trees and Tree Residue*

The definition of renewable biomass in EISA includes planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to December 19, 2007, including land belonging to an Indian tribe or an Indian individual, that is held in trust by the United States or subject to a restriction against alienation imposed by the United States.

We proposed to define the term "planted trees" to include not only trees that were established by human intervention such as planting saplings and artificial seeding, but also trees established from natural seeding by mature trees left undisturbed for such a purpose. Some commenters disagreed with our inclusion of naturally seeded trees in our definition of "planted trees." They argue that an area which is managed for natural regeneration of trees is more akin to a natural forest than a tree plantation, and that the difference between the two types of land should be clear in order to distinguish between the two and to avoid the effective conversion of natural forests to tree plantations under EISA. EPA agrees that the inclusion of natural reseeding in the definition of "planted trees" would make distinguishing between tree plantations and forests difficult or impossible, thus negating the separate restrictions that Congress placed on the two types of land. On the other hand, EPA believes that trees that are naturally seeded and grown together with hand- or machine-planted trees in a tree plantation should not categorically be excluded from qualifying as renewable biomass. Such natural reseeding may occur after planting the majority of trees in a tree plantation, and may be consistent with the management plan for a tree plantation. EPA has decided, therefore, to modify its proposed definition of "planted tree" to be trees harvested from a tree plantation. The term "tree plantation" is defined as a stand of no less than 1 acre composed primarily of trees established by hand- or machine-planting of a seed or sapling, or by coppice growth from the stump or root of a tree that was hand- or machine-planted." The net effect is that as long as a tree plantation consists "primarily" of trees that were hand- or machine planted (or derived therefrom, as described below), then all trees from the tree plantation, including those established from natural seeding by mature trees left undisturbed for such a purpose, will qualify as renewable biomass.

We also received a number of comments suggesting that EPA broaden the definition of planted trees to include other methods of tree regeneration, such as coppice (the production of new stems from stumps or roots), that are frequently used in the forestry industry to regenerate tree plantations. EPA believes that "planted" implies direct human intervention, and that allowing stump-growth from the stump or roots of a tree that was hand- or machine-planted is consistent with this concept. Therefore, today's final rule broadens the concept of "planted trees" from a tree plantation to include "a tree established by hand- or machine-planting of a seed or sapling, or by coppice growth from the stump or root of a tree that was hand- or machine-planted." This new language will appear in the definition of "tree plantation."

In the NPRM, we proposed to define a "tree plantation" as a stand of no fewer than 100 planted trees of similar age and comprising one or two tree species, or an area managed for growth of such trees covering a minimum of one acre. We received numerous comments on our definition of tree plantation. Several commenters urged EPA to define tree plantation more broadly by using the definition from the Dictionary of Forestry- "a stand composed primarily of trees established by planting or artificial seeding," However, this definition does not provide sufficiently clear guidelines for determining whether a given parcel of land would be considered a tree plantation rather than a natural forest. Since trees are considered renewable biomass under RFS2 only if they are harvested from tree plantations, we believe that our proposed definition was clearer and more easily applied in the field. Accordingly, EPA has not adopted the definition of this term from the Dictionary of Forestry. Other commenters argued that there is no technical justification for limiting the number of species or number of trees in a plantation, and that many tree plantations include a variety of species. EPA believes that there is merit in these comments. Accordingly, EPA is finalizing a broadened definition of "tree plantation," by removing the limitations on the number and species of trees. EPA is defining tree plantation as "a stand of no less than 1 acre composed primarily of trees established by hand- or machine-planting of a seed or sapling, or by coppice growth from the stump or root of a tree that was hand- or machine-planted."

We proposed to apply similar management restrictions to tree plantations as would apply to existing agricultural land and also to interpret the EISA language as requiring that to qualify as renewable biomass for renewable fuel production under RFS2, a tree plantation must have been cleared at any time prior to December 19, 2007, and continuously actively managed since

December 19, 2007. Consistent with our final position regarding actively managed existing agricultural land, we are defining the term "actively managed" in the context of tree plantations as managed for a predetermined outcome as evidenced by any of the following that must be traceable to the land in question: sales records for planted trees or slash; purchasing records for seeds, seedlings, or other nursery stock together with other written documentation connecting the land in question to these purchases; a written management plan for silvicultural purposes; documentation of participation in a silvicultural program sponsored by a Federal, state or local government agency; documentation of land management in accordance with an agricultural or silvicultural product certification program; an agreement for land management consultation with a professional forester that identifies the land in question; or evidence of the existence and ongoing maintenance of a road system or other physical infrastructure designed and maintained for logging use, together with one of the above-mentioned documents. Silvicultural programs such as those of the Forest Stewardship Council, the Sustainable Forestry Initiative, the American Tree Farm System, or USDA are examples of the types of programs that could indicate actively managed tree plantations. As with the definition of "actively managed" as it applies to crops from existing agricultural lands, we received extensive comments on this interpretation. As with our final position for crops from existing agricultural lands, we are interpreting the "active management" requirement for tree plantations to apply on the date of EISA's enactment, December 19, 2007. Those tree plantations that were cleared or cultivated and actively managed on December 19, 2007 are eligible for the production of planted trees, tree residue, slash and pre-commercial thinnings for renewable fuel production.

In lieu of the term "tree residue," we proposed to use the term "slash" in our regulations as a more descriptive, but otherwise synonymous, term. According to the Dictionary of Forestry (1998, pp. 168), a source of commonly understood industry definitions, slash is "the residue, e.g., treetops and branches, left on the ground after logging or accumulating as a result of a storm, fire, girdling, or delimbing." We also proposed to clarify that slash can include tree bark and can be the result of any natural disaster, including flooding. We received comments in support of this additional inclusion and are expanding the definition of "slash" to include tree bark and residue resulting from natural disaster, including flooding. We received general support for our proposal to substitute our definition of "slash" for "tree residue," however; several commenters argued that our definition of slash is too narrow to be substituted for "tree residue," which should include woody residues from saw mills and paper mills that process planted trees from tree plantations. EPA agrees that the term "residue" should include this material. Therefore, EPA is expanding the definition of "tree residue" to include residues from processing planted trees at lumber and paper mills, but is limiting it to the biogenically derived portion of the residues that can be traced back to feedstocks meeting the definition of renewable biomass (i.e. planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to December 19, 2007). RINs may only be generated for the fraction of fuel produced that represents the biogenic portion of the tree residue, using the procedures described in ASTM test method D-6866. Thus, if the tree residues are mixed with chemicals or other materials during processing at the lumber or paper mills, producers may only generate RINs for the portion of the mixture that is actually derived from planted trees. EPA's final definition of "tree residue" is "slash and any woody residue generated during the processing of planted trees from actively managed tree plantations for use in lumber, paper, furniture or other applications, providing that such woody residue is not mixed with similar residue from trees that do not originate in actively managed tree plantations.

iii. *Slash and Pre-Commercial Thinnings*

The EISA definition of renewable biomass includes slash and pre-commercial thinnings from non-federal forestlands, including forestlands belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States. However, EISA excludes slash and pre-commercial thinnings from forests or forestlands that are ecological communities with a global or State ranking of critically imperiled, imperiled, or rare pursuant to a State Natural Heritage Program, old growth forest, or late successional forest.

As described in Sec. II.B.4.a.i of this preamble, our definition of "forestland" is generally undeveloped land covering a minimum of 1 acre upon which the primary vegetative species is trees, including land that formerly had such tree cover and that will be regenerated and tree plantations. Tree covered areas in intensive agricultural crop production settings, such as fruit orchards or tree-covered areas in urban setting such as city parks, are not considered forestland. Also as noted in Sec. III.B.4.a.ii of this preamble, we are adopting the definition of slash listed in the Dictionary of Forestry, with the addition of tree bark and residue resulting from natural disaster, including flooding.

As for "pre-commercial thinnings," the Dictionary of Forestry defines the act of such thinning as "the removal of trees not for immediate financial return but to reduce stocking to concentrate growth on the more desirable trees." Because what may now be considered pre-commercial may eventually be saleable as renewable fuel feedstock, we proposed not to include any reference to "financial return" in our definition, but rather to define pre-commercial thinnings as those trees removed from a stand of trees in order to reduce stocking to concentrate growth on more desirable trees. Additionally, we proposed to include diseased trees in the definition of pre-commercial thinnings due to the fact that they can threaten the integrity of an otherwise healthy stand of trees, and their removal can be viewed as reducing stocking to promote the growth of more desirable trees. We sought comment on whether our definition of pre-commercial thinnings should include a maximum diameter and, if so, what the appropriate maximum diameter should be. We received comments on our proposed definition of pre-commercial thinnings that were generally supportive of our proposed definition. Many commenters argued that EPA should not use a maximum tree diameter as a basis for defining pre-commercial thinning as tree diameter varies greatly by forest type and location, making any diameter limitation EPA might set arbitrary. EPA agrees with this assessment. Commenters also argued that pre-commercial thinnings may include other non-tree vegetative material that is removed to promote and improve tree growth. EPA is attempting to utilize standard industry definitions to the extent practicable, and believes that the proposed definition of pre-commercial thinnings, based largely on the Dictionary of Forestry definition with the addition of other vegetative material removed to promote tree growth, is appropriate. Therefore, we are finalizing the proposed definition of "pre-commercial thinnings," with the addition of the phrase "or other vegetative material that is removed to promote tree growth."

We proposed that the State Natural Heritage Programs referred to in EISA are those comprising a network associated with NatureServe, a non-profit conservation and research organization. Individual Natural Heritage Programs collect, analyze, and distribute scientific information about the biological diversity found within their jurisdictions. As part of their activities, these programs survey and apply NatureServe's rankings, such as critically imperiled (S1), imperiled (S2), and rare (S3) to species and ecological communities within their respective borders. NatureServe meanwhile uses data gathered by these Natural Heritage Programs to apply its global rankings, such as critically imperiled (G1), imperiled (G2), or vulnerable (the equivalent of the term "rare," or G3), to species and ecological communities found in multiple States or territories. We proposed and sought comment on prohibiting slash and pre-commercial thinnings from all forest ecological communities with global or State rankings of critically imperiled, imperiled, or vulnerable ("rare" in the case of State rankings) from being used for renewable fuel for which RINs may be generated under RFS2.

We proposed to use data compiled by NatureServe and published in special reports to identify "ecologically sensitive forestland." The reports listed all forest ecological communities in the U.S. with a global ranking of G1, G2, or G3, or with a State ranking of S1, S2, or S3, and included descriptions of the key geographic and biologic attributes of the referenced ecological community. We proposed that the document be incorporated by reference into the definition of renewable biomass in the final RFS2 regulations (and updated as appropriate through notice and comment rulemaking). The document would identify specific ecological communities from which slash and pre-commercial thinnings could not be used as feedstock for the production of renewable fuel that would qualify for RINs under RFS2. Draft versions of the document containing the global and State rankings were placed in the docket for the proposed rule.

EPA received several comments on our proposed interpretation of EISA's State Natural Heritage Program requirement and the reports listing G1-G3 and S1-S3 ecological communities. Several commenters argued that while EISA authorizes EPA to exclude slash and pre-commercial thinnings from S1-3 and G1 and G2 communities, it does not authorize the exclusion of biomass from G3 communities, which are designated as "vulnerable," not "critically imperiled, imperiled or rare," as EISA requires. The commenters further argue that there is little or no environmental benefit to adding G3 communities to the list of lands unavailable for renewable fuel feedstock production, and that their inclusion limits the availability of forest-derived biomass. EPA agrees with these comments, and has drafted today's final rule so as not to specifically exclude from the definition of renewable biomass slash and pre-commercial thinnings from G3-ranked "vulnerable" ecological communities to qualify as renewable biomass for purposes of RFS2. We are interpreting EISA's language to exclude from the definition of renewable biomass any biomass taken from ecological communities in the U.S. with Natural Heritage Programs global ranking of G1 or G2, or with a State ranking of S1, S2, or S3. We are including in today's rulemaking docket (EPA-HQ-OAR-2005-0161) the list of ecological communities fitting this description.

To complete the definition of "ecologically sensitive forestland," we proposed to include old growth and late successional forestland which is characterized by trees at least 200 years old. We received comments on this proposed definition recommending that EPA not use a single tree age in the define old growth and late-successional forests, as this criterion does not apply to all types of forests. While EPA understands that there are a number of criteria for determining whether a forest is old growth and that the criteria differ depending on the type of forest, for purposes of the RFS2 rule, EPA seeks to use definitive criteria that can be applied by non-professionals. EPA is finalizing the definition of "old growth" as proposed.

iv. *Biomass Obtained from Certain Areas at Risk from Wildfire*

The EISA definition of renewable biomass includes biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, at risk from wildfire. We proposed to clarify in the regulations that "biomass" is organic matter that is available on a renewable or recurring basis, and that it must be obtained from within 200 feet of buildings, campgrounds, and other areas regularly occupied by people, or of public infrastructure, such as utility corridors, bridges, and roadways, in areas at risk of wildfire.

Furthermore, we proposed to define "areas at risk of wildfire" as areas located within – or within one mile of – forestland, tree plantations, or any other generally undeveloped tract of land that is at least one acre in size with substantial vegetative cover. We sought comment on two possible implementation alternatives for identifying areas at risk of wildfire. The first proposed alternative would incorporate into our definition of "areas at risk of wildfire" any communities identified as "communities at risk" and covered by a community wildfire protection plan (CWPP). Communities at risk are defined through a process within the document, "Field Guidance - Identifying and Prioritizing Communities at Risk" (National Association of State Foresters, June 2003). CWPPs are developed in accordance with "Preparing a Community Wildfire Protection Plan – A Handbook for Wildland-Urban Interface Communities" (Society of American Foresters, March 2004) and certified by a State Forester or equivalent. We sought comment on incorporating by reference into the final RFS2 regulations a list of "communities at risk" with an approved CWPP. We also sought comment on a second implementation approach, which would incorporate into our definition of "areas at risk of wildfire" any areas identified as wildland urban interface (WUI) land, or land in which houses meet wildland vegetation or are mixed with vegetation. We noted that SILVIS Lab, in the Department of Forest Ecology and Management and the University of Wisconsin, Madison, has, with funding provided by the U.S. Forest Service, mapped WUI lands based on the 2000 Census and the U.S. Geological Survey National Land Cover Data (NLCD), and we sought comment on how best to use this map.

We received comments on the proposal and on the two proposed alternative options for identifying areas at risk of wildfire. A number of commenters argued that EPA should define "areas at risk of wildfire" using an existing definition of WUI from the Healthy Forests Restoration Act (Pub. L. 108-148). Many commenters recommended that EPA include both lands covered by a CWPP as well as lands meeting the Healthy Forests Restoration Act definition of WUI in order to maximize the amount of land available for biomass feedstock and to encourage the removal of hazardous fuel for wildfires. EPA understands that very few communities that might be eligible for a CWPP actually have one in place, due to the numerous administrative steps that must be taken in order to have a CWPP approved, so the option of defining areas at risk of wildfire exclusively by reference to a list of communities with an approved CWPP would be underinclusive of all lands that a professional forester would consider to be at risk of wildfire. Furthermore, EPA believes that the statutory definition of WUI from the Healthy Forests Restoration Act (Pub. L. 108-148) is too vague using directly in implementing the RFS2 program. If EPA used this WUI definition, individual plots of land would have to be assessed by a professional forester on a case-by-case basis in order to determine if they meet the WUI definition, creating an expensive burden for landowners seeking to sell biomass from their lands as renewable fuel feedstocks.

In light of the comments received and the need for a simple way for landowners and renewable fuel producers to track the status of particular plots of land, for the final rule we are identifying "areas at risk of wildfire" as those areas identified as wildland urban interface. Those areas are depicted and mapped at http://silvis.forest.wisc.edu/Library/WUILibrary.asp. The electronic WUI map is a readily accessible reference tool that was prepared by experts in the field of identifying areas at risk of wildfire, and is thus an ideal reference for purposes of implementing RFS2. EPA has included in the rulemaking docket instructions on using the WUI map to find the status of a plot of land.

v. *Algae*

EISA specifies that "algae" qualify as renewable biomass. EPA did not propose a definition for this term. A number of commenters have requested clarification, specifically asking whether cyanobacteria (also known as blue-green algae), diatoms, and angiosperms are within the definition. Technically, the term "algae" has recently been defined as "thallophytes (plants lacking roots, stems and leaves) that have chlorophyll a as their primary photosynthetic pigment and lack a sterile covering of cells around the reproductive cells."[5] Algae are relatively simple organisms that are virtually ubiquitous, occurring in freshwater, brackish water, saltwater, and terrestrial habitats. When present in water, they may be suspended, or grow attached to various substrates. They range in size from unicellular to among the longest living organisms (e.g. sea kelp). There is some disagreement among scientists as to whether cyanobacteria should be considered bacteria or algae. Some consider them to be bacteria because of their cellular organization and biochemistry. However, others find it more significant that they contain chlorophyll a, which differs from the chlorophyll of bacteria which are photosynthetic, and also because free oxygen is liberated in blue-green algal photosynthesis but not in that of the bacteria.[6] EPA believes that it furthers the purposes of EISA to interpret the term "algae" in EISA broadly to include cyanobacteria, since doing so will make available another possible feedstock for renewable fuel production that will further the energy independence and greenhouse gas reduction objectives of the Act. Further, EPA expects that cyanobacteria used in biofuel production would be cultivated, as opposed to harvested, and therefore that there would be no significant impact from use of cyanobacteria for biofuel production on naturally occurring algal populations. Diatoms are generally considered by the scientific community to be algae,[7] and, consistent with this general scientific consensus, EPA interprets the EISA definition of algae to include them. Microcrop angiosperms, however, do not meet the definition of algae, even if they live in an aquatic habitat, since they are relatively more complex organisms than the

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[5] Phycology, Robert Edward Lee, Cambridge University Press, 2008, page 3.
[6] See, generally, Introduction to the Algae. Structure and Reproduction, by Harold C. Bold and Michael J. Wynne, Prentice-Hall Inc. 1978, page 31.
[7] See id.

algae. A discussion of microcrop angiosperms is included above in the discussion of "planted crops and crop residue."

b. Implementation of Renewable Biomass Requirements

Our proposed approach to the treatment of renewable biomass under RFS2 was intended to define the conditions under which RINs can be generated as well as the conditions under which renewable fuel can be produced or imported without RINs. Our proposed and final approaches to both of these areas are described in more detail below.

i. *Ensuring That RINs Are Generated Only For Fuels Made From Renewable Biomass*

The effect of adding EISA's definition of renewable biomass to the RFS program is to ensure that renewable fuels are only eligible for the program if made from certain feedstocks, and if some of those feedstocks come from certain types of land. In the context of our regulatory program, this means that RINs could only be generated if it can be established that the feedstock from which the fuel was made meets EISA's definitions of renewable biomass include land restrictions. Otherwise, no RINs could be generated to represent the renewable fuel produced or imported. The EISA language does not distinguish between domestic renewable fuel feedstocks and renewable fuel feedstocks that come from abroad, so our final rule requires similar feedstock affirmation and recordkeeping requirements for both RIN-generating domestic renewable fuel producers and RIN-generating foreign producers or importers.

We acknowledge that incidental contaminants can be introduced into feedstocks during cultivation, transport or processing. It is not EPA's intent that the presence of such contaminants should disqualify the feedstock as renewable biomass. The final regulations therefore stipulate that the term "renewable biomass" includes incidental contaminants related to customary feedstock production and transport that are present in feedstock that otherwise meets the definition if such incidental contaminants are impractical to remove and occur in de minimus levels. By "related to customary feedstock production and transport," we refer to contaminants related to crop production, such as soil or residues related to fertilizer, pesticide and herbicide applications to crops, as well as contaminants related to feedstock transport, such as nylon rope used to bind feedstock materials. It would also include agricultural contaminants introduced to the feedstock during sorting or shipping, such as miscellaneous sorghum grains present in a load of corn kernels. However, contamination is not related to customary feedstock production and transport, so such feedstocks would not qualify, and in particular, any hazardous waste or toxic chemical contaminant in feedstock would disqualify the feedstock as renewable biomass.

ii. *Whether RINs Must Be Generated For All Qualifying Renewable Fuel*

Under RFS1, virtually all renewable fuel is required to be assigned a RIN by the producer or importer. This requirement was developed and finalized in the RFS1 rulemaking in order to address stakeholder concerns, particularly from obligated parties, that the number of available RINs should reflect the total volume of renewable fuel used in the transportation sector in the U.S. and facilitate program compliance. EISA has dramatically increased the mandated volumes of renewable fuel that obligated parties must ensure are produced and used in the U.S. At the same time, EISA makes it more difficult for renewable fuel producers to demonstrate that they have fuel that qualifies for RIN generation by restricting qualifying renewable fuel to that made from "renewable biomass." The inclusion of such restrictions under RFS2 may mean that, in some situations, a renewable fuel producer would prefer to forgo the benefits of RIN generation to avoid the cost of ensuring that its feedstocks qualify for RIN generation. If a sufficient number of renewable fuel producers acted in this way, it could lead to a situation in which not all qualifying fuel is assigned RINs, thus resulting in a shortage of RINs in the market that could force obligated parties into non-compliance even though biofuels are being produced and used. Another possible outcome would be that the demand for and price of RINs would increase significantly, making compliance by obligated parties more costly and difficult than necessary and raising prices for consumers.

With these concerns in mind, EPA proposed to preserve in RFS2 the RFS1 requirement that RINs be generated for all qualifying renewable fuel. We also proposed that renewable fuel producers maintain records showing that they utilized feedstocks made from renewable biomass if they are generating RINs, or, if they are not generating RINs, that they did not use feedstocks that qualify as renewable biomass. However, we considered this matter further, and we realize that the implication of these proposed requirements is that renewable fuel producers would be caught in the untenable position of being forced to participate in the RFS2 program (register, keep records, etc.) even if they are unable to generate RINS because their feedstocks do not meet the definition of renewable biomass. We received many comments on the proposed requirement to generate RINs for all qualifying renewable fuel. Most commenters argued that the requirement to keep records for non-qualifying renewable fuels was excessively onerous and served little purpose for the program.

After considering the comments received, EPA has determined that this requirement would be overly burdensome and unreasonable for producers. The burden stems from the requirement that producers prove that their feedstocks do not qualify if they are not generating RINs. If the data did not exist or could not be obtained, producers could not produce the fuel, even if no RINs would be generated. Thus, for the final rule, EPA is requiring only that producers that do generate RINs have the requisite records (as discussed in section II.B.4.c.i. of this preamble) documenting that their fuel is produced from feedstocks meeting the definition of renewable biomass. Non-RIN generating producers need not maintain any paperwork related to their feedstocks and their origins.

Although EPA is not requiring that RINs be generated for all qualifying renewable fuel, EPA is seeking to avoid situations where biofuels are produced, but RINs are not made available to the market for compliance. EPA received comments requesting that we consider a provision in which any volume of renewable fuel for which RINs were not generated would be an obligated volume for that producer, to serve as a disincentive for those producers who might not generate RINs in order to avoid the RFS program requirements. While EPA is not finalizing this provision in today's rule, we may consider a future rulemaking to promulgate a provision such as this if we find that EISA volumes are not being met due to producers declining to generate RINs for their qualifying renewable fuel. We also note that it is ultimately the availability of qualifying renewable fuel, as determined in part by the number of RINs in the marketplace, that will determine the extent to which EPA should issue a waiver of RFS requirements on the basis of inadequate domestic supply. It is in the interest of renewable fuel producers to avoid a situation where a waiver of the EISA volume requirements appears necessary. EPA encourages renewable fuel producers to generate RINs for all fuel that is made from feedstocks meeting the definition of renewable biomass and that meets the GHG emissions reduction thresholds set out in EISA. Please see section II.D.6 for additional discussion of this issue.

c. Implementation Approaches for Domestic Renewable Fuel

Consistent with RFS1, renewable fuel producers will be responsible for generating Renewable Identification Numbers (RINs) under RFS2. In order to determine whether or not their fuel is eligible for generating RINs, renewable fuel producers will generally need to have at least basic information about the origin of their feedstocks, to ensure they meet the definition of renewable biomass. In the proposal, EPA described and sought comment on several approaches for implementing the land restrictions on renewable biomass contained in EISA.

The proposed approach for ensuring that producers generate RINs properly was that EPA would require that renewable fuel producers obtain documentation about their feedstocks from their feedstock supplier(s) and take the measures necessary to ensure that they know the source of their feedstocks and can demonstrate to EPA that they fall within the EISA definition of renewable biomass. EPA would require renewable fuel producers who generate RINs to affirm on their renewable fuel production reports that the feedstock used for each renewable fuel batch meets the definition of renewable biomass. EPA would also require renewable fuel producers to maintain sufficient records to support these claims. Specifically, we proposed that renewable fuel producers who use planted crops or crop residue from existing agricultural land, or who use planted trees or slash from actively managed tree plantations, would be required to have copies of their feedstock producers' written records that serve as evidence of land being actively managed (or fallow, in the case of agricultural land) since December 2007, such as sales records for planted crops or trees, livestock, crop residue, or slash; a written management plan for agricultural or silvicultural purposes; or, documentation of participation in an agricultural or silvicultural program sponsored by a Federal, state or local government agency. In the case of all other biomass, we proposed to require renewable fuel producers to have, at a minimum, written records from their feedstock supplier that serve as evidence that the feedstock qualifies as renewable biomass.

We sought comment on this approach generally as well as other methods of verifying renewable fuel producers' claims that feedstocks qualify as renewable biomass. EPA received extensive comments on the proposed approach. Many affected parties argued that the proposed approach would pose an unnecessary recordkeeping burden on both feedstock and renewable fuel producers when, in practice, new lands will not be cleared, at least in the near future, for purposes of growing renewable fuel feedstocks. Commenters argued that individual recordkeeping was onerous, when compliance with the renewable biomass requirements could be determined through the use of existing data and third-party programs. Commenters contend that the recordkeeping and feedstock tracking requirements are particularly arduous for corn, soybeans and other agricultural crops that are used as renewable fuel feedstocks due to both the maturity and the highly fungible nature of those feedstock systems. In contrast, other commenters argued that recordkeeping and reporting requirements are necessary to ensure that feedstocks are properly verified as renewable biomass to prevent undesirable impacts on natural ecosystems and wildlife habitat globally.

We also sought comment on the possible use under EISA of non-governmental, third-party verification programs used for certifying and tracking agricultural and forest products from point of origin to point of use both within the U.S. and outside the U.S. We examined third party organizations that certify specific types of biomass from croplands and organizations that certify forest lands, including the Roundtable on Sustainable Palm Oil, the Basel Criteria for Responsible Soy Production, the Roundtable on Sustainable Biofuels (RSB) and the Better Sugarcane Initiative (BSI). Additionally, we examined the work of the international Soy Working Group, the Brazilian Association of Vegetable Oil Industries (ABIOVE) and Brazil's National Association of Grain Exporters (ANEC), Greenpeace, Verified Sustainable Ethanol initiative, the Sustainable Agriculture Network (SAN), the Forest Stewardship Council (FSC), American Tree Farm program and Sustainable Forestry Initiative (SFI). We proposed not to solely rely on any existing third-party verification program to implement the land restrictions on renewable biomass under RFS2 for several reasons. These programs are limited in the scope of products they certify, the acreage of land certified through third parties in the U.S. covers only a small portion of the total available land estimated to qualify for renewable biomass production under the EISA definition, and none of the existing third-party systems had definitions or criteria that perfectly match the land use definitions and restrictions contained in the EISA definition of renewable biomass.

We received several comments indicating that producers would like to use evidence of their participation in these types of programs to prove that their feedstocks meet the definition of renewable biomass. Others argued that while, at this time, the requirements of third party programs may not encompass all of the restrictions and requirements of EISA's renewable biomass definition, the programs may alter their criteria in the future to parallel EISA's requirements. EPA agrees that this is a possibility and, in the future, will consider the use of these programs in order to simplify compliance with the renewable biomass requirements. We encourage fuel producers to work to identify changes to such programs that could allow them to be used as a viable compliance option.

In the proposal, EPA also acknowledged that land restrictions contained within the definition of renewable biomass may not, in practice, result in a significant change in agricultural practices, since biomass from nonqualifying lands may still be used for non-fuel (e.g. food) purposes. Therefore, we sought comment on a stakeholder suggestion to establish a baseline level of production of biomass feedstocks such that reporting and recordkeeping requirements would be triggered only when the baseline production levels of feedstocks used for biofuels were exceeded. Additionally, EPA offered as an alternative the use of existing satellite and aerial imagery and mapping software and tools to implement the renewable biomass provisions of EISA. We received numerous comments in support of these options. Commenters argued that USDA collects and maintains ample data on land use that EPA could use to demonstrate that, due to increasing crop yields and other considerations, agricultural land acreage will not expand, at least in the near term, to accommodate the increased renewable fuel obligations of RFS2.

EPA also sought comment on an additional alternative in which EPA would require renewable fuel producers to set up and administer a company-wide quality assurance program that would create an additional level of rigor in the implementation scheme for the EISA land restrictions on renewable biomass. EPA is not finalizing this company-wide quality assurance program approach, but rather, is encouraging the option for an industry-wide quality assurance program, as described in the following section, to be administered.

i. *Recordkeeping and Reporting for Feedstocks*

After considering the comments we received on the proposed approach, EPA is finalizing reporting and recordkeeping requirements comparable to those in the approach we discussed in the proposed rule for all categories of renewable biomass, with the exception of planted crops and crop residue from agricultural land in the United States, which will be covered by the aggregate compliance approach discussed below in Section II.B.4.c.iii. EPA believes that these requirements on the fuel producer utilizing feedstocks other than crops and crop residue are necessary to ensure that the definition of renewable biomass is being met, and to allow feedstocks to be traced from their original producer to the renewable fuel production facility. Furthermore, we believe that, in most cases, feedstock producers will already have or will be able to easily generate the specified documentation for renewable fuel producers necessary to provide them with adequate assurance that the feedstock in question meets the definition of renewable biomass.

Under today's rule, all renewable fuel producers must maintain written records from their feedstock suppliers for each feedstock purchase that identify the type and amount of feedstocks and where the feedstock was produced and that are sufficient to verify that the feedstock qualifies as renewable biomass. Specifically, renewable fuel producers must maintain maps and/or electronic data identifying the boundaries of the land where the feedstock was produced, product transfer documents (PTDs) or bills of lading tracing the feedstock from that land to the renewable fuel production facility, and other written records that serve as evidence that the feedstock qualifies as renewable biomass. We believe the maps or electronic data can be easily generated using existing web-based information.

Producers using planted trees and tree residue from tree plantations must maintain additional documentation that serves as evidence that the tree plantation was cleared prior to December 19, 2007, and actively managed as a tree plantation on December 19, 2007. This documentation must consist of the following types of records which must be traceable to the land in question: sales records for planted trees or slash; purchasing records for fertilizer, weed control, or reseeding, including seeds, seedlings, or other nursery stock together with other written documentation connecting the land in question to these purchases; a written management plan for silvicultural purposes; documentation of participation in a silvicultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with a silvicultural product certification program; an agreement for land management consultation with a professional forester that identifies the land in question; or evidence of the existence and ongoing maintenance of a road system or other physical infrastructure designed and maintained for logging use. There are many existing programs, such as those administered by USDA and independent third-party certifiers, that could be used as documentation that verifies that feedstock from certain land qualifies as renewable biomass. For example, many tree plantation owners already participate in a third-party certification program such as FSC or SFI. Written proof of participation by a tract of land in a program of this type on December 19, 2007 would be sufficient to show that a tree plantation was cleared prior to that date and that it was actively managed on that date. The tree plantation owner would need to send copies of this documentation to the renewable fuel producer when supplying them with biomass that will be used as a renewable fuel feedstock.

We anticipate that the recordkeeping requirements will result in renewable fuel producers amending their contracts and modifying their supply chain interactions to satisfy the requirement that producers have documented assurance and proof about their feedstock's origins. Enforcement will rely in part on EPA's review of renewable fuel production reports and attest engagements of renewable fuel producers' records. EPA will also consult other data sources, including any data made available by USDA, and may conduct site visits or inspections of feedstock producers' and suppliers' facilities.

The reporting requirements for renewable biomass in today's final rule include, as proposed, include an affirmation by the renewable fuel producer for each batch of renewable fuel for which they generate RINs that the feedstocks used to produce the batch meet the definition of renewable biomass. Additionally, the final reporting requirements include a quarterly report to be sent to EPA by each renewable fuel producer that includes a summary of the types and volumes of feedstocks used throughout the quarter, as well as electronic data or maps identifying the land from which those feedstocks were harvested. Producers need not provide duplicate maps if purchasing feedstocks multiple times from one plot of land; producers may cross-reference the previously submitted map. Producers will also be required to keep records tracing the feedstocks from the land to the renewable fuel production facility, other written records from their feedstock suppliers that serve as evidence that the feedstock qualifies as renewable biomass, and for producers using planted trees or tree residue from tree plantations, written records that serve as evidence that the land from which the feedstocks were obtained was cleared prior to December 19, 2007 and actively managed on that date. These requirements will apply to renewable fuel producers using feedstocks from foreign sources (unless special approvals are granted in the future, as described below), or from domestic sources, except for planted crops or crop residue (discussed below).

This approach will be integrated into the existing registration, recordkeeping, reporting, and attest engagement procedures for renewable fuel producers. It places the burden of implementation and enforcement on renewable fuel producers rather than bringing feedstock producers and suppliers directly under EPA regulation, minimizing the number of regulated parties under RFS2.

EPA also sought comment on, and is finalizing as an option, an alternative approach in which EPA allows renewable fuel producers and renewable fuel feedstock producers and suppliers to develop a quality assurance program for the renewable fuel production supply chain, similar to the model of the successful Reformulated Gasoline Survey Association. While individual renewable fuel producers may still choose to comply with the individual renewable biomass recordkeeping and reporting requirements rather than participate in a quality assurance program, we believe that this preferred alternative could be less costly than an individual compliance demonstration, and it would add a quality assurance element to RFS2. Those participating renewable fuel producers would be presumed to be in compliance with the renewable biomass requirements unless and until the quality assurance program finds evidence to the contrary. Under today's rule, renewable fuel producers must choose either to comply with the individual renewable biomass recordkeeping and reporting described above, or they must participate in the quality assurance program.

The quality assurance program must be carried out by an independent auditor funded by renewable fuel producers and feedstock suppliers. The program must consist of a verification program for participating renewable fuel producers and renewable feedstock producers and handlers designed to provide independent oversight of the feedstock handling processes that are required to determine if a feedstock meets the definition of renewable biomass. Under this option, a participating renewable fuel producer and its renewable feedstock suppliers and handlers would have to participate in the funding of an organization which arranges to have an independent auditor conduct a program of compliance surveys. The compliance audit must be carried out by an independent auditor pursuant to a detailed survey plan submitted to EPA for approval by November 1 of the year preceding the year in which the alternative compliance program would be implemented. The compliance survey program plan must include a statistically supportable methodology for the survey, the locations of the surveys, the frequency of audits to be included in the survey, and any other elements that EPA determines are necessary to achieve the same level of quality assurance as the individual recordkeeping and reporting requirements included in the RFS2 regulations.

Under this alternative compliance program, the independent auditor would be required to visit participating renewable feedstock producers and suppliers to determine if the biomass they supply to renewable fuel producers meets the definition of renewable biomass. This program would be designed to ensure representative coverage of participating renewable feedstock producers and suppliers. The auditor would generate and report the results of the surveys to EPA each calendar quarter. In addition, where the survey finds improper designations or handling, the renewable fuel producers would be responsible for identifying and addressing the root cause of the problem. The renewable fuel producers would have to take corrective action to retire the appropriate number of invalid RINs depending on the violation. EPA received comments from a number of parties who were supportive of this option as an alternative and less-burdensome way of ensuring that renewable fuel feedstocks meet the definition of renewable biomass. EPA believes this option to be an efficient and effective means of implementing and enforcing the renewable biomass requirements of EISA, and has therefore included it as a compliance option in today's final rule.

ii. *Approaches for Foreign Producers of Renewable Fuel*

The EISA renewable biomass language does not distinguish between domestic renewable fuel and fuel feedstocks and renewable fuel and fuel and feedstocks that come from abroad. EPA proposed that foreign producers of renewable fuel that is exported to the U.S. be required to meet the same compliance obligations as domestic renewable fuel producers, as well as some additional measure, discussed in Section II.C., designed to facilitate EPA enforcement in other countries. These proposed obligations include facility registration and submittal of independent engineering reviews (described in Section II.C below), and reporting, recordkeeping, and attest engagement requirements. The proposal also would have included for foreign producers the same obligations that domestic producers have for verifying that their feedstock meets the definition of renewable biomass, such as certifying on each renewable fuel production report that their renewable fuel feedstock meets the definition of renewable biomass and working with their feedstock suppliers to ensure that they receive and maintain accurate and sufficient documentation in their records to support their claims.

(1) *RIN-generating importers*

EPA proposed to allow importers to generate RINs for renewable fuel they are importing into the U.S. only if the foreign producer of that renewable fuel had not already done so. Under the proposal, in order to generate RINs, importers would need to obtain information from the registered foreign producers concerning the point of origin of their fuel's feedstock and whether it meets the definition of renewable biomass. Therefore, we proposed that in the event that a batch of foreign-produced renewable fuel does not have RINs accompanying it when it arrives at a U.S. port, an importer must obtain documentation that proves that the fuel's feedstock meets the definition of renewable biomass (as described in Section II.B.4.a. of this preamble) from the fuel's producer, who must have registered with the RFS program and conducted a third-party engineering review. With such documentation, the importer could generate RINs prior to introducing the fuel into commerce in the U.S.

We sought comment on this proposed approach and whether and to what extent the approaches for ensuring compliance with the EISA's land restrictions by foreign renewable fuel producers should differ from the proposed approach for domestic renewable fuel producers. We received comments on the proposed implementation option for importers of foreign renewable fuel. Some argue that the proposed recordkeeping requirements for imported fuel were overly burdensome. On the other hand, others argued that importers, similarly to domestic producers, should be required to obtain information that can serve as evidence that the feedstocks meet the definition of renewable biomass, in order to avoid fraud. Some commenters also argued that importers should be able to generate RINs for fuel imported from foreign producers that are not registered with EPA under the RFS2 program.

For the final rule, EPA is requiring that importers may only generate RINs for renewable fuel if the foreign producer has not already done so. The foreign producers must be registered with EPA under the RFS2 program, and must have conducted an independent engineering review. Furthermore, we are requiring that importers obtain from the foreign producer and maintain in their records written documentation that serves as evidence that the renewable fuel for which they are generating RINs was made from feedstocks meeting the definition of renewable biomass. The foreign producer that originally generated the fuel must ensure that these feedstock records are transferred with each batch of fuel and ultimately reach the RIN-generating importer. A requirement that importers maintain these renewable biomass records is consistent with the renewable biomass recordkeeping requirements imposed on domestic producers of renewable fuel.

(2) *RIN-generating foreign producers*

Foreign producers that intend to generate RINs would be required to designate renewable fuel intended for export to the U.S. as such, segregate the volume until it reaches the U.S., and post a bond to ensure that penalties can be assessed in the event of a violation, as discussed in Section II.D.2.b. Similarly to domestic producers of renewable fuel, foreign producers must obtain and maintain written documentation from their feedstock providers that can serve as evidence that their feedstocks meet the definition of renewable biomass. Foreign producers may also develop a quality assurance program for their renewable fuel production supply chain, as described above. However, while domestic renewable fuel producers using crops or crop residues may rely on the aggregate compliance approach described below to ensure that their feedstocks are renewable biomass, this approach is not available at this time to foreign renewable fuel producers, as described below.

EPA believes that the renewable biomass recordkeeping provisions are necessary in order for EPA to ensure that RINs are being generated for fuel that meets EISA's definition of renewable fuel. Just as for domestic producers, foreign producers must maintain evidence that the fuel meets the GHG reduction requirements and is made from renewable biomass.

iii. *Aggregate Compliance Approach for Planted Crops and Crop Residue from Agricultural Land*

In light of the comments received on the proposed renewable biomass recordkeeping requirements and implementation options, EPA sought assistance from USDA in determining whether existing data and data sources might suggest an alternative method for verifying compliance with renewable biomass requirements associated with the use of crops and crop residue for renewable fuel production. Taking into consideration publicly available data on agricultural land available from USDA and USGS as well as expected economic incentives for feedstock producers, EPA has determined that an aggregate compliance approach is appropriate for certain types of renewable biomass, namely planted crops and crop residue from the United States.

Under the aggregate compliance approach, EPA is determining for this rule the total amount of "existing agricultural land" in the U.S. (as defined above in Section II.B.4.a.) at the enactment date of EISA, which is 402 million acres. EPA will monitor total agricultural land annually to determine if national agricultural land acreage increases above this 2007 national aggregate baseline. Feedstocks derived from planted crops and crop residues will be considered to be consistent with the definition of renewable biomass and renewable fuel producers using these feedstocks will not be required to maintain specific renewable biomass records as described below unless and until EPA determines that the 2007 national aggregate baseline is exceeded. If EPA finds that the national aggregate baseline is exceeded, individual recordkeeping and reporting requirements as described below will be triggered for renewable fuel producers using crops and crop residue. We believe that the aggregate approach will fully ensure that the EISA renewable biomass provisions related to crops and crop residue are satisfied, while also easing the burden for certain renewable fuel producers and their feedstock suppliers vis-à-vis verification that their feedstock qualifies as renewable biomass.

As discussed in more detail below, there are five main factors supporting the aggregate compliance approach we are taking for planted crops and crop residue. First, EPA is using data sets that allow us to obtain an appropriately representative estimate of the agricultural lands available under EISA for the production of crops and crop residue as feedstock for renewable fuel production. Second, USDA data indicate an overall trend of agricultural land contraction. These data, together with EPA economic modeling, suggest that 2007 aggregate baseline acreage should be sufficient to support EISA renewable fuel obligations and other foreseeable demands for crop products, at least in the near term, without clearing and cultivating additional land. Third, EPA believes that existing economic factors for feedstock producers favor more efficient utilization practices of existing agricultural land rather than converting non-agricultural lands to crop production. Fourth, if, at any point, EPA finds that the total amount of land in use for the production of crops including crops for grazing and forage is equal or greater than 397 million acres (i.e. within 5 million acres of EPA's established 402 million acre baseline), EPA will conduct further investigations to evaluate whether the presumption built into the aggregate compliance approach remains valid. Lastly, EPA has set up a trigger mechanism that in the event there are more than the baseline amount of acres of cropland, pastureland and CRP land in production, renewable fuel producers will be required to meet the same individual or consortium-based recordkeeping and reporting requirements applicable to RIN-generating renewable fuel producers using other feedstocks. Taken together, these factors give EPA high confidence that the aggregate compliance approach for domestically grown crops and crop residues meets the statutory obligation to ensure feedstock volumes used to meet the renewable fuel requirements also comply with the definition of renewable biomass.

(1) *Analysis of Total Agricultural Land in 2007*

As described in Section II.B.4.a. above, EPA is defining "existing agricultural land" for purposes of the EISA land use restrictions on crops and crop residue to include cropland, pastureland and CRP land that was cleared and actively managed or fallow and nonforested on the date of EISA enactment. To determine the aggregate total acreage of existing agricultural land for the aggregate compliance approach on the date of EISA enactment, EPA obtained from USDA data representing total cropland (including fallow cropland), pastureland, and CRP land in 2007 from three independently gathered national land use data sources (discussed in further detail below): the Farm Service Agency (FSA) Crop History Data, the USDA Census of Agriculture (2007), and the satellite-based USDA Crop Data Layer (CDL). In addition, CRP acreage is provided by FSA's annually published "Conservation Reserve Program: Summary and Enrollment Statistics." By definition, the cropland, pastureland, and CRP land included in these data sources for 2007 were cleared or cultivated on the date of EISA enactment (December 19, 2007) and, consistent with the principles set forth in Section II.4.a.i, would be considered "actively managed" or fallow and nonforested on that date. These categories of lands include those from which traditional crops, such as corn, soy, wheat and sorghum, would likely be grown. Therefore quantification of cropland, pastureland, and CRP land from these data sources represents a reasonable assessment of the acreage in the United States that is available under the Act for the production of crops and crop residues that could satisfy the definition of renewable biomass in EISA.

Conservation Reserve Program Data. FSA reports CRP enrollment acreage each year in the publication "Conservation Reserve Program: Summary and Enrollment Statistics." The CRP program includes the general CRP, the Conservation Reserve Enhancement Program (CREP), and the Farmable Wetlands Program (FWP). The Wetlands Reserve Program (WRP) and Grasslands Reserve Program (GRP) are not under CRP and are not included in the total agricultural land figure in this rulemaking. The 2007 CRP acreage was 36.7 million acres. This is an exact count of acreage within the CRP program in 2007.

Farm Service Agency Crop History Data. The FSA maintains annual records of field-level land use data for all farms enrolled in FSA programs. Almost all national cropland and pastureland is reported through FSA and recorded in this data set. We used the "Cropland" category to determine total agricultural land. Pastureland is reported by farms under the category "Cropland" as cropland used for grazing and forage under the crop type "mixed forage." Timber land and any grazed native grass was removed from the "Cropland" category, because these land types represent either forestland or rangeland, which are not within the definition of existing agricultural land. CRP lands and other conservation program lands are also reported as cropland. Because GRP and WRP lands are not within the definition of "existing agricultural land" as defined in today's regulations, they were also subtracted from the "Cropland" category total. FSA Crop History Data show that there was 402 million acres of agricultural land, as defined here, in the U.S. in 2007 (See Table II.B.4-1).

Table II.B.4-1
Total U.S. Agricultural Land in 2007 from USDA Data Sources

Land Category	FSA Crop History Data	Agricultural Census Data
Cropland and Pastureland	365	367
CRP Land	37	37
Total Land	402	404

USDA Census of Agriculture. USDA conducts a full census of the U.S. agricultural sector once every five years. The data are available for the U.S., each of the 50 States, and for each county. The most recent census available is the 2007 Census of Agriculture. For the purpose of this rulemaking, USDA provided EPA total acreage and 95% confidence intervals for the Census category "Total Cropland," which includes the sub-categories "Harvested cropland," "Cropland used only for pasture and grazing," and "Other cropland." WRP and GRP acreage are included in "Other cropland," so, for purposes of this rulemaking, they were subtracted from the sub-category number (see above). The analysis excluded the "Permanent rangeland and pasture" category, as the pasture data cannot be separated from rangeland in this category. Total CRP acreage in 2007 was added to "Total cropland." With these adjustments, the Census of Agriculture showed 404 million acres (95% confidence range 401-406 million acres) of existing agricultural land as defined in today's rule, in the U.S. in 2007 (See Table II.B.4-1).

Crop Data Layer. The USDA National Agricultural Statistics Service (NASS) Crop Data Layer (CDL) is a raster, geo-referenced, crop-specific land cover data layer suitable for use in geographic information systems (GIS) analysis. Based on satellite data, the CDL has a ground resolution of 56 meters and was verified using FSA surveys. The CDL covers 21 major agricultural states for 2007 and therefore cannot be used to determine a 2007 national aggregate agricultural land baseline. There will be full coverage of the 48 contiguous states for 2009, and the CDL can be used for analysis validation purposes during monitoring. From 2010 onward, it coverage of the 48 contiguous states will be dependent on available funding. GIS analyses of the CDL will include all cropland and pastureland data for each state. To ensure that non-pasture grasslands are not included in the final sum, all areas of the "Grassland herbaceous" category from the U.S. Geological National Land Cover Data layer (NLCD) that overlap the CDL layers are removed from the total agricultural land number. Producer and user accuracies[8] are available for the CDL crop categories.

Primary Data Source Selection for Aggregate Compliance Approach. EPA has determined that the FSA Crop History Data will be used as the data set on which the total existing agricultural land baseline will be based for the aggregate compliance approach. The FSA Crop History Data is the only complete data set for 2007 that is collected annually, enabling EPA to monitor agricultural land expansion or contraction from year to year using a consistent data set. The total existing agricultural land value derived from FSA Crop History Data rests within the 95% confidence interval of the 2007 Census of Agriculture and is only 2 million acres less than the Census of Agriculture point estimate. The Census of Agriculture provides slightly fuller coverage than the FSA Crop History Data due to the nature of the data collection; however, given that both data collection systems have consistent and long-standing methodologies, the disparity between the two should remain approximately constant. Therefore, the FSA Crop History Data will provide a consistent data set for analyzing any expansion or contraction of total national agricultural land in the U.S.

During its annual monitoring, EPA will use the FSA Crop History Data and the CDL analyses as a secondary source to validate our annual assessment. In years when the Census of Agriculture is updated, this data will also be used to validate our annual assessment. Other data sources, such as the annual NASS Farms, Land in Farms and Livestock Operations may also be useful as secondary data checks. Lastly, EPA intends to consider, as appropriate, other data sources for the annual monitoring analysis of total agricultural land as new technologies and data sources come online that would improve the accuracy and robustness of annual monitoring.

(2) *Aggregate Agricultural Land Trends over Time*

The Census of Agriculture (conducted every five years) shows that U.S. agricultural land has decreased by 44 million acres from 1997 to 2007, indicating an overall decade trend of contraction of agricultural land utilization despite some year-to-year variations that can be seen by reference to the annual FSA Crop History records (See Table II.B.4-2 and Table II.B.4-3). EPA's FASOM modeling results, which model full EISA volumes in 2022, support this contraction trend, indicating that total cropland, pastureland, and CRP land in the U.S. in 2022, under a scenario of full renewable fuel volume as required by EISA, would be less than the 2007

[8] "Producer Accuracy" indicates the probability that a groundtruth pixel will be correctly mapped and measures errors of omission; "User Accuracy" indicates the probability that a pixel from the classification actually matches the groundtruth data and measures errors of omission.

national acreage reported in the FSA Crop History Data (See preamble Section VII and RIA Chapter 5).

Table II.B.4-2
Total agricultural land (as defined in Section II.B.4.a) counted in the Census of Agriculture from 1997-2007

Census Year	Total Agricultural Land (millions of acres)
2007 404	
2002*	431
1997*	445

*2002 data do not include farms with land in FWP or CREP.

Table II.B.4-3
Total agricultural land (as defined in Section II.B.4.a) recorded in FSA Crop History Data from 2005-2007

Year	Total Agricultural Land (millions of acres)
2007 402	
2006	393
2005	392

(3) *Aggregate Compliance Determination*

The foundation of the aggregate compliance approach is establishment of a baseline amount of eligible agricultural land that was cleared or cultivated and actively managed or fallow and non-forested on December 19, 2007. Based on USDA-FSA Crop History Data, EPA is establishing a baseline of 402 million acres of U.S. agricultural land, as defined in Section II.B.4.a and based upon the methods described in Section II.B.4.c.iii.(1), that is eligible for production of planted crops and crop residue meeting the EISA definition of renewable biomass. EPA will monitor total U.S. agricultural land annually, using FSA Crop History Data as a primary determinant, but using other data sources for support (See Section II.4.c.iii.(1)). If, at any point, EPA finds that the total land in use for the production of crops, including crops for grazing and forage, is greater than 397 million acres (i.e. within 5 million acres of EPA's established 402 million acre baseline), EPA will conduct further investigations to evaluate whether the presumption built into the aggregate compliance approach remains valid. Additionally, if EPA determines that the data indicates that this 2007 baseline level of eligible agricultural land has been exceeded, EPA will publish in the Federal Register a finding to that effect, and additional requirements will be triggered for renewable fuel producers to verify that they are using planted crops and crop residue from "existing agricultural land" as defined in today's rule as their renewable fuel feedstock. EPA's findings will be published by November 30, at the latest. If in November the 402 million acres baseline is found to be exceeded, then on July 1 of the following year, renewable fuel producers using feedstocks qualifying for this aggregate compliance approach, namely planted crops and crop residue from the United States, will be required to comply with the recordkeeping and reporting requirements applicable to producers using other types of renewable biomass, as described in the previous sections. This includes the option that fuel producers could utilize a third-party consortium to demonstrate compliance.

EPA acknowledges that it is possible that under this approach some of the land available under EISA for crop production on the date of EISA enactment could be retired and other land brought into production, without altering the assessment of the aggregate amount of cropland, pastureland and CRP land. Under EISA, crops or crop residues from the new lands would not qualify as renewable biomass. However, EPA expects such shifts in acreage to be de minimus, as long as the total aggregate amount of agricultural land does not exceed the 2007 national aggregate baseline. EPA expects that new lands are unlikely to be cleared for agricultural purposes for two reasons. First, it can be assumed that most undeveloped land that was not used as agricultural land in 2007 is generally not suitable for agricultural purposes and would serve only marginally well for production of renewable fuel feedstocks. Due to the high costs and significant inputs that would be required to make the non-agricultural land suitable for agricultural purposes, it is highly unlikely that farmers will undertake the effort to "shift" land that is currently non-agricultural into agricultural use. Second, crop yields are projected to increase, reducing the need for farmers to clear new land for agricultural purposes. We believe that this effect is reflected in the overall trend, discussed earlier, of an overall contraction in agricultural land acreage over time.

If EPA determines that the baseline is exceeded, and that individual compliance with the renewable biomass reporting and recordkeeping requirements is triggered, renewable fuel producers using crops and crop residue as a feedstock for renewable fuel would become responsible, beginning July 1 of the following year, for meeting individual recordkeeping and reporting requirements related to renewable biomass verification. These requirements are identical to those that apply to producers using other types of renewable biomass feedstocks, such as planted trees from tree plantations, as described in the previous sections. Renewable fuel producers generating RINs under the RFS2 program would continue to be required to affirm (through EMTS – EPA Moderated Transaction System) for each batch of renewable fuel that their feedstocks meet the definition of renewable biomass. Additionally, producers would send a quarterly report to EPA that includes a summary of the types and volumes of feedstocks used throughout the quarter, as well as electronic data or maps identifying the land from which those feedstocks were harvested.

Furthermore, those RIN-generating renewable fuel producers will be required to obtain and maintain in their files written records from their feedstock suppliers for each feedstock purchase that identify where the feedstocks were produced and that are sufficient to verify that the feedstocks qualify as renewable biomass. This includes maps and/or electronic data identifying the boundaries of the land where the feedstock was produced, PTDs or bills of lading tracing the feedstock from that land to the renewable fuel production facility, and other written records that serve as evidence that the feedstock qualifies as renewable biomass. Finally, producers using planted crops and crop residue must maintain additional documentation that serves as evidence that the agricultural land used to produce the crop or crop residue was cleared or cultivated and actively managed or fallow, and nonforested on December 19, 2007. This documentation must consist of the following types of records which must be traced to the land in question: sales records for planted crops, crop residue, or livestock, purchasing records for land treatments such as fertilizer, weed control, or reseeding or a written agricultural management plan or documentation of participation in an agricultural program sponsored by a Federal, State or local government agency.

Alternatively, if the baseline is exceeded and the requirements are triggered for individual producer verification that their feedstocks are renewable biomass renewable fuel producers may choose to work with other renewable fuel producers as well as feedstock producers and suppliers to develop a quality assurance program for the renewable fuel production supply chain. This quality assurance program would take the place of individual accounting and would consist of an independent third party quality-assurance survey of all participating renewable fuel producers and their feedstock suppliers, completed in accordance with an industry-developed, EPA-approved plan, to ensure that they are utilizing feedstocks that meet the definition of renewable biomass. An in-depth discussion of this industry survey option is included in the previous section.

While the aggregate compliance approach is appropriate for planted crops and crop residues from agricultural land in the United States, due in part to certain additional or different constraints imposed by EISA, the aggregate approach cannot be applied, at this time, to the other types of renewable biomass. Renewable fuel producers utilizing these types of renewable biomass, including planted trees and tree residues from tree plantations, slash and pre-commercial thinnings from non-federal forestland, animal waste, separated yard and food waste, etc., will be subject to the individual reporting and recordkeeping requirements discussed in the previous section.

Additionally, EPA is not finalizing the aggregate compliance approach for foreign producers of renewable fuel. EPA does not, at this time, have sufficient data to make a finding that non-domestically grown crops and crop residues used in renewable fuel production satisfy the definition of renewable biomass. Nevertheless, if, in the future, adequate land use data becomes available to make a finding that, in the aggregate, crops and crop residues used in renewable fuel production in a particular country satisfy the definition of renewable biomass, EPA is willing to consider an aggregate compliance approach for renewable biomass on a country by country basis, in lieu of the individual recordkeeping and reporting requirements.

d. Treatment of Municipal Solid Waste (MSW)

The statutory definition of "renewable biomass" does not include a reference to municipal solid waste (MSW) as did the definition of "cellulosic biomass ethanol" in the Energy Policy Act of 2005 (EPAct), but instead includes "separated yard waste and food waste."

We solicited comment on whether EPA can and should interpret EISA as including MSW that contains yard and/or food waste within the definition of renewable biomass. On the one hand, the reference in the statutory definition to "separated yard waste and food waste," and the lack of reference to other components of MSW (such as waste paper and wood waste) suggests that only yard and food wastes physically separated from other waste materials satisfy the definition of renewable biomass. On the other hand, we noted that EISA does not define the term "separated," and so does not specify the degree of separation required. We also noted that there was some evidence in the Act that Congress did not intend to exclude MSW entirely from the definition of renewable biomass. The definition of "advanced biofuel" includes a list of fuels that are "eligible for consideration" as advanced biofuel, including "ethanol derived from waste material" and biogas "including landfill gas."

As an initial matter, we note that some materials clearly fall within the definition of "separated yard or food waste." The statute itself identifies "recycled cooking and trap grease" as one example of separated food waste. An example of separated yard waste is the leaf waste that many municipalities pick up at curbside and keep separate from other components of MSW for mulching or other uses. However, a large quantity of food and yard waste is disposed of together with other household waste as part of MSW. EPA estimates that about 120 million tons of MSW are disposed of annually much of it inextricably mixed with yard and especially food waste. This material offers a potentially reliable, abundant and inexpensive source of feedstock for renewable fuel production which, if used, could reduce the volume of discarded materials sent to landfills and could help achieve both the GHG emissions reductions and energy independence goals of EISA. Thus, EPA believes we should consider under what conditions yard and food waste that is present in MSW can be deemed sufficiently separated from other materials to qualify as renewable biomass.

One commenter stated that it is clear that MSW does not qualify as renewable biomass under EISA, since the 2005 Energy Policy Act explicitly allowed for qualifying renewable fuel to be made from MSW, and EISA has no mention of it. Commenters from the renewable fuel industry generally favored maximum flexibility for the use of MSW in producing qualifying fuels under EISA, offering a variety of arguments based on the statutory text and reasons why it would benefit the environment and the nation's energy policy to do so. They favored either 1) a determination that unsorted MSW can be used as a feedstock for advanced biofuel even if it does not meet the definition of renewable biomass, 2) that the Act be interpreted to include MSW as renewable biomass, or 3) that MSW from which varying amounts of recyclable materials have been removed could qualify as renewable biomass. A consortium of ten environmental groups said that for EISA volume mandates to be met, it is important to take advantage of biomass resources from urban wastes that would otherwise be landfilled. They urged that post-recycling residues (i.e., those wastes that are left over at material recovery facilities after separation and recycling) would fit within the letter and spirit of the definition of renewable biomass.

EPA does not believe that the statute can be reasonably interpreted to allow advanced biofuel to be made from material that does not meet the definition of renewable biomass as suggested in the first approach. The definition of advanced biofuel specifies that it is a form of "renewable fuel," and renewable fuel is defined in the statute as fuel that is made from renewable biomass. While the definition of advanced biofuel includes a list of materials that "may" be "eligible for consideration" as advanced biofuel, and that list includes "ethanol derived from waste materials" and biogas "including landfill gas," the fact that the specified items are "eligible for consideration" indicates that they do not necessarily qualify but must meet the definitional requirements – being "renewable fuel" made from renewable biomass and having life cycle greenhouse gas emissions that are at least 50% less than baseline fuel. There is nothing in the statute to suggest that Congress used the term "renewable fuel" in the definition of "advanced biofuel" to have a different meaning than the definition provided in the statute. The result of the commenter's first approach would be that general renewable fuel and cellulosic biofuel would be required to be made from renewable biomass because the definitions of those terms specifically refer to renewable biomass, whereas advanced biofuel and biomass-based diesel would not, because their definitions refer to "renewable fuel" rather than "renewable biomass." EPA can discern no basis for such a distinction. EPA believes that the Act as a whole is best interpreted as requiring all types of qualifying renewable fuels under EISA to be made from renewable biomass. In this manner the land and feedstock restrictions that Congress deemed important in the context of biofuel production apply to all types of renewable fuels.

EPA also does not agree with the commenter who suggested that the listing in the definition of renewable biomass of "biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, at risk from wildfire" should be interpreted to include MSW. It is clear that the term "at risk of wildfire" modifies the entire sentence, and the purpose of the listing is to make the biomass that is removed in wildfire minimization efforts, such as brush and dead woody material, available for renewable fuel production. Such material does not typically include MSW. Had Congress intended to include MSW in the definition of renewable biomass, EPA believes it would have clearly done so, in a manner similar to the approach taken in EPAct

EPA also does not believe that it would be reasonable to interpret the reference to "separated yard or food waste" to include unsorted MSW. Although MSW contains yard and food waste, such an approach would not give meaning to the word "separated."

We do believe, however, that yard and food wastes that are part of MSW, and are separated from it, should qualify as renewable biomass. MSW is the logical source from which yard waste and food waste can be separated. As to the degree of separation required, some commenters suggested a simple "post recycling" test be appropriate. They would leave to municipalities and waste handlers a determination of how much waste should be recycled before the residue was used as a feedstock for renewable fuel production. EPA believes that such an approach would not guarantee sufficient "separation" from MSW of materials that are not yard waste or food waste to give meaning to the statutory text. Instead, EPA believes it would be reasonable in the MSW context to interpret the word "separated" in the term "separated yard or food waste" to refer to the degree of separation to the extent that is reasonably practicable. A large amount of material can be, and is, removed from MSW and sold to companies that will recycle the material. EPA believes that the residues remaining after reasonably practicable efforts to remove recyclable materials other than food and yard waste (including paper, cardboard, plastic, textiles, metal and glass) from MSW should qualify as separated yard and food waste. This MSW-derived residue would likely include some amount of residual non-recyclable plastic and rubber of fossil fuel origin, much of it being wrapping and packaging material for food. Since this material cannot be practicably separated from the remaining food and yard waste, EPA believes it is incidental material that is impractical to remove and therefore appropriate to include in the category of separated food and yard waste. In sum, EPA believes that the biogenic portion of the residue remaining after paper, cardboard, plastic, textiles metal and glass have been removed for recycling should qualify as renewable biomass. This interpretation is consistent with the text of the statute, and will promote the productive use of materials that would otherwise be landfilled. It will also further the goals of EISA in promoting energy independence and the reduction of GHG emissions from transportation fuels.

EPA notes there are a variety of recycling methods that can be used, including curbside recycling programs, as well as separation and sorting at a material recovery facility (MRF). For the latter, the sorting could be done by hand or by automated equipment, or by a combination of the two. Sorting by hand is very labor intensive and much slower than using an automated system. In most cases the 'by-hand' system produces a slightly cleaner stream, but the high cost of labor usually makes the automated system more cost-effective. Separation via MRFs is generally very efficient and can provide comparable if not better removal of recyclables to that achieved by curbside recycling.

Based on this analysis, today's rule provides that those MSW-derived residues that remain after reasonably practicable separation of recyclable materials other than food and yard waste is renewable biomass. What remains to be addressed is what regulatory mechanisms should be used to ensure the appropriate generation of RINs when separated yard and food waste is used as a feedstock. We are finalizing two methods.

The first method would apply primarily to a small subset of producers who are able to obtain yard and/or food wastes that have been kept separate since waste generation from the MSW waste stream. Examples of such wastes are lawn and leaf waste that have never entered the general MSW waste stream. Typically, such wastes contain incidental amounts of materials such as the plastic twine used to bind twigs together, food wrappers, and other extraneous materials. As with our general approach to the presence of incidental, de minimus contaminants in feedstocks that are unintentionally present and impractical to remove, the presence of such material in separated yard or food waste will not disqualify such wastes as renewable biomass, and the contaminants may be disregarded by producers and importers generating RINs . (See definition of renewable biomass and 80.1426(f)(1).) Waste streams kept separate since generation from MSW that consist of yard waste are expected to be composed almost entirely of woody material or leaves, and therefore will be deemed to be composed of cellulosic materials. Waste streams consisting of food wastes, however, may contain both cellulosic and non-cellulosic materials. For example, a food processing plant may generate both wastes that are primarily starches and sugars (such as carrot and potato peelings, as well as fruits and vegetables that are discarded) as well as corn cobs and other materials that are cellulosic. We will deem waste streams consisting of food waste to be composed entirely of non-cellulosic materials, and qualifying as advanced biofuels, unless the producer demonstrates that some portion of the food waste is cellulosic. The cellulosic portion would then qualify as cellulosic biofuel. The method for quantifying the cellulosic and non-cellulosic portions of the food waste stream is to be described in a written plan which must be submitted to EPA under the registration procedures in 80.1450(b)(vii) for approval and which indicates the location of the facility from which wastes are obtained, how identification and quantification of waste material is to be accomplished, and evidence that the wastes qualify as fully separated yard or food wastes. The producer must also maintain records regarding the source of the feedstock and the amounts obtained.

The second method would involve use as feedstock by a renewable fuel producer of the portion of MSW remaining after reasonably practical separation activities to remove recyclable materials, resulting in a separated MSW-derived residue that qualifies as separated yard and food waste. Today's rule requires that parties that intend to use MSW-derived residue as a feedstock for RIN-generating renewable fuel production ensure that reasonably practical efforts are made to separate recyclable paper, cardboard, textiles, plastics, metal and glass from the MSW, according to a plan that is submitted by the renewable fuel producer and approved by EPA under the registration procedures in 80.1450(b)(viii). In determining whether the plan submittals provide for reasonably practicable separation of recyclables EPA will consider: 1) the extent and nature of recycling that may have occurred prior to receipt of the MSW material by the renewable fuel producer, 2) available recycling technology and practices, and 3) the technology or practices selected by the fuel producer, including an explanation for such selection and reasons why other technologies or practices were not selected. EPA asks that any CBI accompanying a plan or a party's justification for a plan be segregated from the non-CBI portions of the submissions, so as to facilitate disclosure of the non-CBI portion of plan submittals, and approved plans, to interested members of the public.

Producers using this second option, will need to determine what RINs to assign to a fuel that is derived from a variety of materials, including yard waste (largely cellulosic) and food waste (largely starches and sugar), as well as incidental materials remaining after reasonably practical separation efforts such as plastic and rubber of fossil origin. EPA has not yet evaluated the lifecycle greenhouse gas performance of fuel made from such mixed sources of waste, so is unable at this time to assign a D code for such fuel. However, if a producer uses ASTM test method D-6866 on the fuel made from MSW-derived feedstock, it can determine what portion of the rule is of fossil and non-fossil origin. The non-fossil portion of the fuel will likely be largely derived from cellulosic materials (yard waste, textiles, paper, and construction materials), and to a much smaller extent starch-based materials (food wastes). Unfortunately, EPA is not aware of a test method that is able to distinguish between cellulosic- and starch-derived renewable fuel. Under these circumstances, EPA believes that it is appropriate for producers to base RIN assignment on the predominant component and, therefore, to assume that the biogenic portion of their fuel is entirely of cellulosic origin. The non-biogenic portion of the fuel, however, would not qualify for RINs at this time. Thus, in sum, we are providing via the ASTM testing method an opportunity for producers using a MSW-derived feedstock to generate RINs only for the biogenic portion of their renewable fuel. There is no D code for the remaining fossil-derived fraction of the fuel in today's rule nor for the entire volume of renewable fuel produced when using MSW-derived residue as a feedstock. The petition process for assigning such codes in today's rule can be used for such purpose.

Procedures for the use of ASTM Method D-6866 are detailed in 40 CFR 80.1426(f)(9) of today's rule. We solicited comment on this method, and while the context of the discussion of method D-6866 was with respect to using it for gasoline (see 74 FR 24951), the comments we received provided us information on the method itself. Also, commenters were supportive of its use. Fuel producers must either run the ASTM D-6866 method for each batch of fuel produced, or run it on composite samples of the food and yard waste-derived fuel derived from post-recycling MSW residues. Producers will be required at a minimum to take samples of every batch of fuel produced over the course of one month and combine them into a single composite sample. The D-6866 test would then be applied to the composite sample, and the resulting non-fossil derived fraction will be deemed cellulosic biofuel, and applied to all batches of fuel produced in the next month to determine the appropriate number of RINs that must be generated. The producer would be required to recalculate this fraction at least monthly. For the first month, the producer can estimate the non-fossil fraction, and then make a correction as needed in the second month. (The procedure using the ASTM D-6866 method applies not only to the waste-derived fuel discussed here but also to all partially renewable transportation fuels, and is discussed in further detail in Section II.D.4 See also the regulations at §80.1426(f)(4)).

The procedures for assigning D codes to the fuel produced from such wastes are discussed in further detail in Section II.D.5.

One commenter suggested that biogas from landfills should be treated in the same manner as renewable fuel produced from MSW. EPA agrees with the commenter to a certain extent. The definition of "advanced biofuels" in EISA identifies "Biogas (including landfill gas and sewage waste treatment gas) produced through the conversion of organic matter from renewable biomass" as "eligible for consideration" as an advanced biofuel. However, as with MSW, the statute requires that advanced biofuel be a "renewable fuel" and that such fuel be made from "renewable biomass." The closest reference within the definition of renewable biomass to landfill material is "separated yard or food waste." However, in applying the interpretation of "separated" yard and food waste described above for MSW to landfill material, we come to a different result. Landfill material has by design been put out of practical human reach. It has been disposed of in locations, and in a manner, that is designed to be permanent. For example, modern landfills are placed over impermeable liners and sealed with a permanent cap. In addition, the food and yard waste present in a landfill has over time become intermingled with other materials to an extraordinary extent. This occurs in the process of waste collection, shipment, and disposal, and subsequently through waste decay, leaching and movement within the landfill. Additionally, we note that the process of biogas formation in a landfill provides some element of separation, in that it is formed only from the biogenic components of landfill material, including but not strictly limited to food and yard waste. Thus, plastics, metal and glass are effectively "separated" out through the process of biogas formation. As a result of the intermixing of wastes, the fact that biogas is formed only from the biogenic portion of landfill material, and the fact that landfill material is as a practical matter inaccessible for further separation, EPA believes that no further practical separation is possible for landfill material and biogas should be considered as produced from separated yard and food waste for purposes of EISA. Therefore, all biogas from landfills is eligible for RIN generation

We have considered whether to require biogas producers to use ASTM Method D-6866 to identify the biogenic versus non-biogenic fractions of the fuel. However, as noted above, biogas is not formed from non-biogenic compounds in landfills. (Kaplan, et. al., 2009)[9] Thus, no purpose would be solved in using the ASTM method in the biogas context.

C. Expanded Registration Process for Producers and Importers

In order to implement and enforce the new restrictions on qualifying renewable fuel under RFS2, we are revising the registration process for renewable fuel producers and importers. Under the RFS1 program, all producers and importers of renewable fuel who produce or import more than 10,000 gallons of fuel annually must register with EPA's fuels program prior to generating RINs. Renewable fuel producer and importer registration under the RFS1 program

[9] Kaplan, et. al. (2009). "Is it Better to Burn or Bury Waste for Clean Electricity Generation?" *Environmental Science & Technology* 2009 *43* (6), 1711-1717 (Found in Table S1 of supplemental material to the article, at http://pubs.acs.org/doi/suppl/10.1021/es802395e/suppl_file/es802395e_si_001.pdf)

consists of filling out two forms: 3520-20A (Fuels Programs Company/Entity Registration), which requires basic contact information for the company and basic business activity information and 3520-20B (Gasoline Programs Facility Registration) or 3520-20B1 (Diesel Programs Facility Registration), which require basic contact information for each facility owned by the producer or importer. More detailed information on the renewable fuel production facility, such as production capacity and process, feedstocks, and products was not required for most producers or importers to generate RINs under RFS1 (producers of cellulosic biomass ethanol and waste-derived ethanol are the exception to this).

Additionally, EPA recommends companies register their renewable fuels or fuel additives under title 40 CFR part 79 as a motor vehicle fuel. In fact, renewable fuels intended for use in motor vehicles will be required to be registered under title 40 CFR part 79 prior to any introduction into commerce. Manufactures and subsequent parties of fuels and fuel additives not registered under part 79 will be liable for separate penalties under 40 CFR parts 79 and 80 in the event their unregistered product is introduced into commerce for use in a motor vehicle. Further if a registered fuel or fuel additive is used in manner that is not consistent with their product's registration under part 79 the manufacturer and subsequent parties will be liable for penalties under parts 79 and 80. If EPA determines based on the company's registration that they are not producing renewable fuel, the company will not be able to generate RINs and the RINs generated for fuel produced from nonrenewable sources will be invalidated.

Due to the revised definitions of renewable fuel under EISA, we proposed to expand the registration process for renewable fuel producers and importers in order to implement the new program effectively. We received a number of comments that opposed the expanded registration as commenters deemed it overly burdensome, costly and unnecessary. However, EPA is finalizing the proposed expanded registration requirements for the following reasons. The information to be collected through the expanded registration process is essential to generating and assigning a certain category of RIN to a volume of fuel. Additionally, the information collected is essential to determining whether the feedstock used to produce the fuel meets the definition of renewable biomass, whether the lifecycle greenhouse gas emissions of the fuel meets a certain GHG reduction threshold and, in some cases, whether the renewable fuel production facility is considered to be grandfathered into the program. Therefore, we are requiring producers, including foreign producers, and importers that generate RINs to provide us with information on their feedstocks, facilities, and products, in order to implement and enforce the program and have confidence that producers and importers are properly categorizing their fuel and generating RINs. The registration procedures will be integrated with the new EPA Moderated Transaction System, discussed in detail in Section III.A of this preamble.

1. Domestic Renewable Fuel Producers

Information on products, feedstocks, and facilities contained in a producer's registration will be used to verify the validity of RINs generated and their proper categorization as either cellulosic biofuel, biomass-based diesel, advanced biofuel, or other renewable fuel. In addition, producers of renewable fuel from facilities that qualify for the exemption from the 20% GHG reduction threshold (as discussed in Section II.B.3) must provide information that demonstrates when the facility commenced construction, and that establishes the baseline volume of the fuel. For those facilities that would qualify as grandfathered but are not in operation we are allowing until May 1, 2013 to submit and receive approval for a complete facility registration. This provision does not require actual fuel production, but simply the filing of registration materials that assert a claim for exempt status. It will benefit both fuel producers, who will likely be able to more readily collect the required information if it is done promptly, and EPA enforcement personnel seeking to verify the information. However, given the potentially significant implications of this requirement for facilities that may qualify for the exemption but miss the registration deadline, the rule also provides that EPA may waive the requirement if it determines that the submission is verifiable to the same extent as a timely-submitted registration.

With respect to products, we are requiring that producers provide information on the types of renewable fuel and co-products that a facility is capable of producing. With respect to feedstocks, we are requiring producers to provide to EPA a list of all the different feedstocks that a renewable fuel producer's facility is likely to use to convert into renewable fuel. With respect to the producer's facilities, two types of information must be reported to the Agency. First, producers must describe each facility's fuel production processes (e.g., wet mill, dry mill, thermochemical, etc.), and thermal/process energy source(s). Second, in order to determine what production volumes would be grandfathered and thus deemed to be in compliance with the 20% GHG threshold, we are requiring evidence and certification of the facility's qualification under the definition of "commence construction" as well as information necessary to establish its renewable fuel baseline volume per the requirement outlined in Section II.B.3 of this preamble.

EPA proposed to require that renewable fuel producers have a third-party engineering review of their facilities prior to generating RINs under RFS2, and every 3 years thereafter. EPA received comments that the on-site engineering review was overly burdensome, unnecessary and costly. A number of commenters noted that the time allotted for conducting the reviews, between the rule's publication and prior to RIN generation, is not adequate for producers to hire an engineer and conduct the review for all of their facilities. Several commenters requested that on-site licensed engineers be allowed to conduct any necessary facility reviews.

EPA is finalizing the proposed requirement for an on-site engineering review of facilities producing renewable fuel due to the variability of production facilities, the increase in the number of categories of renewable fuels, and the importance of ensuring that that RINs are generated in the correct category. Without these engineering reviews, we do not believe it would be possible to implement the RFS2 program in a manner that ensured the requirements of EISA were being fulfilled. Additionally, the engineering review provides a check against fraudulent RIN generation. In order to establish the proper basis for RIN generation, we are requiring that every renewable fuel producer have the on-site engineering review of their facility performed in conjunction with his or her initial registration for the new RFS program. The engineering reviews must be conducted by independent third parties who can maintain impartiality and objectivity in evaluating the facilities and their processes. Additionally, the on-site engineering review must be conducted every three years thereafter to verify that the fuel pathways established in the initial registration are still applicable. These requirements apply unless the renewable fuel producer updates its facility registration information to qualify for a new RIN category (i.e., D code), in which case the review needs to be performed within 60 days of the registration update. Finally, producers are required to submit a copy of their independent engineering review to EPA, for verification and enforcement purposes.

2. Foreign Renewable Fuel Producers

Under RFS1, foreign renewable fuel producers of cellulosic biomass ethanol and waste-derived ethanol may apply to EPA to generate RINs for their own fuel. For RFS2, we proposed that foreign producers of renewable fuel meet the same requirements as domestic producers, including registering information about their feedstocks, facilities, and products, as well as submitting an on-site independent engineering review of their facilities at the time of registration for the program and every three years thereafter. These requirements apply to all foreign renewable fuel producers who plan to export their products to the U.S. as part of the RFS2 program, whether the foreign producer generates RINs for their fuel or an importer does.

Foreign producers, like domestic producers, must also undergo an independent engineering review of their facilities, conducted by an independent third party who is a licensed professional engineer (P.E.), or foreign equivalent who works in the chemical engineering field. The independent third party must provide to EPA documentation of his or her qualifications as part of the engineering review, including proof of appropriate P.E. license or foreign equivalent. The third-party engineering review must be conducted by both foreign producers who plan to generate RINs and those that don't generate RINs but anticipate their fuel will be exported to the United States by an importer who will generate the RINs.

3. Renewable Fuel Importers

We are requiring importers who generate RINs for imported fuel that they receive without RINs may only do so under certain circumstances. If an importer receives fuel without RINs, the importer may only generate RINs for that fuel if they can verify the fuel pathway and that feedstocks use meet the definition of renewable biomass. An importer must rely on his supplier, a foreign renewable fuel producer, to provide documentation to support any claims for their decision to generate RINs. An importer may have an agreement with a foreign renewable fuel producer for the importer to generate RINs if the foreign producer has not done so already. However, the foreign renewable fuel producer must be registered with EPA and must have had a third-party engineering review conducted, as noted above, in order for EPA to be able to verify that the renewable biomass and GHG reduction requirements of EISA are being fulfilled. Section II.D.2.b describes the RIN generating restrictions and requirements for importers under RFS2.

4. Process and Timing

We are making forms for expanded registration for renewable fuel producers and importers, as well as forms for registration of other regulated parties, available electronically with the publication of this final rule. Paper registration forms will only be accepted in exceptional cases. Registration forms must be submitted and accepted by the EPA by July 1, 2010, or 60 days prior to a producer producing or importer importing any renewable fuel, whichever dates comes later. If a producer changes its fuel pathway (feedstock, production process, or fuel type) to not listed in his registration information on file with EPA but the change will not incur a change of RIN category for the fuel (i.e., a change in the appropriate D code), the producer must update his registration information within seven (7) days of the change. However, if the fuel producer changes its fuel pathway in a manner that would result in a change in its RIN category (and thus a new D code), such an update would need to be submitted at least 60 days prior to the change, followed by submittal of a complete on-site independent engineering review of the producer's facility also within 60 days of the change. If EPA finds that these deadlines and requirements have not been met, or that a facility's registered profile, dictated by the various parameters for product, process and feedstock, does not reflect actual products produced, processes employed, or feedstocks used, then EPA reserves the right to void, ab initio, any affected RINs generated and may impose significant penalties. For example a newly registered (i.e. not grandfathered) ethanol production facility claims in their registration that they qualify to generate RINs based upon the use of two advanced engineering practices 1) corn oil fractionation and 2) production of wet DGS co-product that is, at a minimum, 35% of its total DGS produced annually. However, during an audit of the producer's records, it is found that of all their DGS produced, less than 15% was wet. In this example, the producer has committed a violation that results in the disqualification of their eligibility to generate RINs; that is, they no longer have an eligible pathway that demonstrates qualification with the 20% GHG threshold requirement for corn ethanol producers. As such any and all RINs produced may be deemed invalid and the producer may be subject to Clean Air Act penalties.

The required independent engineering review as discussed above for domestic and foreign renewable fuel producers is an integral part of the registration process. The agency recognizes, through comments received, that there are significant concerns involving timing necessary and ability to produce a completed engineering review to satisfy registration requirements. Since the publication of the RFS2 NPRM, we have delivered consistently a message stating that advanced planning and preparation was necessary from all parties, EPA and the regulated community inclusive, for successful implementation of this program. In an effort to reduce demand on engineering resources, we are allowing grandfathered facilities an additional six months to submit their engineering review. This will direct the focus of engineering review resources on producers of advanced, cellulosic and biomass based diesel. EPA fully expects these producers of advanced renewable fuels to meet the engineering review requirement; however, if they are having difficulties producing engineer's reports prior to April 1, we ask that they contact us.

D. Generation of RINs

Under RFS2, each RIN will continue to be generated by the producer or importer of the renewable fuel, as in the RFS1 program. In order to determine the number of RINs that must be generated and assigned to a batch of renewable fuel, the actual volume of the batch of renewable fuel must be multiplied by the appropriate Equivalence Value. The producer or importer must also determine the appropriate D code to assign to the RIN to identify which of the four standards the RIN can be used to meet. This section describes these two aspects of the generation of RINs. Other aspects of the generation of RINs, such as the definition of a batch, as well as the assignment of RINs to batches, will remain unchanged from the RFS1 requirements. We received several comments regarding the method for calculating temperature standardization of biodiesel and address this issue in Section III.G.

1. Equivalence Values

For RFS1, we interpreted CAA section 211(o) as allowing us to develop Equivalence Values representing the number of gallons that can be claimed for compliance purposes for every physical gallon of renewable fuel. We described how the use of Equivalence Values adjusted for renewable content and based on energy content in comparison to the energy content of ethanol was consistent with the sections of EPAct that provided extra credit for cellulosic and waste-derived renewable fuels, and the direction that EPA establish "appropriate" credit for biodiesel and renewable fuel volumes in excess of the mandated volumes. We also noted that the use of Equivalence Values based on energy content was an appropriate measure of the extent to which a renewable fuel would replace or reduce the quantity of petroleum or other fossil fuel present in a fuel mixture. EPA stated that these provisions indicated that Congress did not intend to restrict EPA discretion in implementing the program to utilizing a straight volume measurement of gallons. See 72 FR 23918-23920, and 71 FR 55570-55571. The result was an Equivalence Value for ethanol of 1.0, for butanol of 1.3, for biodiesel (mono alkyl ester) of 1.5, and for non-ester renewable diesel of 1.7.

In the NPRM we noted that EISA made a number of changes to CAA section 211(o) that impacted our consideration of Equivalence Values in the context of the RFS2 program. For instance, EISA eliminated the 2.5-to-1 credit for cellulosic biomass ethanol and waste-derived ethanol and replaced this provision with large mandated volumes of cellulosic biofuel and advanced biofuels. EISA also expanded the program to include four separate categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel) and included GHG thresholds in the definitions of each category. Each of these categories of renewable fuel has its own volume requirement, and thus there will exist a guaranteed market for each. As a result of these new requirements, we indicated that there may no longer be a need for additional incentives for certain fuels in the form of Equivalence Values greater than 1.0.

In the NPRM we co-proposed and took comment on two options for Equivalence Values:

1. Equivalence Values would be based on the energy content and renewable content of each renewable fuel in comparison to denatured ethanol, consistent with the approach under RFS1, with the addition that biomass-based diesel standard would be based on energy content in comparison to biodiesel.

2. All liquid renewable fuels would be counted strictly on the basis of their measured volumes, and the Equivalence Values for all renewable fuels would be 1.0 (essentially, Equivalence Values would no longer apply).

In response to the NPRM, some stakeholders pointed to the aforementioned changes brought about by EISA as support for a straight volume approach to Equivalence Values, and argued that it had always been the intent of Congress that the statutory volume mandates be treated as straight volumes. Stakeholders taking this position were generally producers of corn ethanol. However, a broad group of other stakeholders including refiners, biodiesel producers, a broad group of advanced biofuel producers, fuel distributor and States indicated that the first option for an energy-based approach to Equivalence Values was both supported by the statute and necessary to provide for equitable treatment of advanced biofuels. They noted that EISA did not change certain of the statutory provisions EPA looked to for support under RFS1 in establishing Equivalence Values based on relative volumetric energy content in comparison to ethanol. For instance, CAA 211(o) continues to direct EPA to determine an "appropriate" credit for biodiesel, and also directs EPA to determine the "appropriate" amount of credit for renewable fuel use in excess of the required volumes. Had Congress intended to change these provisions they could have easily done so. Moreover, some stakeholders argued that the existence of four standards is not a sufficient reason to eliminate the use of energy-based Equivalence Values for RFS2. The four categories are defined in such a way that a variety of different types of renewable fuel could qualify for each category, such that no single specific type of renewable fuel will have a guaranteed market. For example, the cellulosic biofuel requirement could be met with both cellulosic ethanol or cellulosic diesel. As a result, the existence of four standards under RFS2 does not obviate the value of standardizing for energy content, which provides a level playing field under RFS1 for various types of renewable fuels based on energy content.

Some stakeholders who supported an energy-based approach to Equivalence Values also argued that a straight volume approach would be likely to create a disincentive for the development of new renewable fuels that have a higher energy content than ethanol. For a given mass of feedstock, the volume of renewable fuel that can be produced is roughly inversely proportional to its energy content. For instance, one ton of biomass could be gasified and converted to syngas, which could then be catalytically reformed into either 80 gallons of ethanol (and another 14 gal of other alcohols) or 50 gallons of diesel fuel (and naphtha)[10]. If RINs were assigned on a straight volume basis, the producer could maximize the number of RINs he is able to generate and sell by producing ethanol instead of diesel. Thus, even if the market would otherwise lean towards demanding greater volumes of diesel, the greater RIN value for producing ethanol may favor their production instead. However, if the energy-based Equivalence Values were maintained, the producer could assign 1.7 RINs to each gallon of diesel made from biomass in comparison to 1.0 RIN to each gallon of ethanol from biomass, and the total number of RINs generated would be essentially the same for the diesel as it would be for the ethanol. The use of energy-based Equivalence Values could thus provide a level playing field in terms of the RFS program's incentives to produce different types of renewable fuel from the available feedstocks. The market would then be free to choose the most appropriate renewable fuels without any bias imposed by the RFS regulations, and the costs imposed on different types of renewable fuel through the assignment of RINs would be more evenly aligned with the ability of those fuels to power vehicles and engines, and displace fossil fuel-based gasoline or diesel. Since the technologies for producing more energy-dense fuels such as cellulosic diesel are still in the early stages of development, they may benefit from not having to overcome the disincentive in the form of the same Equivalence Value based on straight volume.

Based on our interpretation of EISA as allowing the use of energy-based Equivalence Values, and because we believe it provides a level playing field for the development of different

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[10] Another example would be a fermentation process in which one ton of cellulose could be used to produce either 70 gallons of ethanol or 55 gallons of butanol.

fuels that can displace the use of fossil fuels, and that this approach therefore furthers the energy independence goals of EISA, we are finalizing the energy-based approach to Equivalence Values in today's action. We also note that a large number of companies have already made investments based on the decisions made for RFS1, and using energy-based Equivalence Values will maintain consistency with RFS1 and ease the transition into RFS2. Insofar as renewable fuels with volumetric energy contents higher than ethanol are used, the actual volumes of renewable fuel that are necessary to meet the EISA volume mandates will be smaller than those shown in Table I.A.1-1. The impact on the physical volume will depend on actual volumes of various advanced biofuels produced in the future. The main scenario modeled for this final rule includes a forecast for considerable volumes of relatively high energy diesel fuel made from renewable biomass, and still results in a physical volume mandate of 30.5 billion gallons. The energy-based approach results in the advanced biofuel standard being automatically met during the first few years of the program. For instance, the biomass-based diesel mandated volume for 2010 is 0.65 billion gallons, which will be treated as 0.975 billion gallons (1.5 x 0.65) in the context of meeting the advanced biofuel standard. Since the mandated volume for advanced biofuel in 2010 is 0.95 billion gallons, this requirement is automatically met by compliance with the biomass-based diesel standard.

Although we are finalizing an energy-based approach to Equivalence Values, we believe that Congress intended the biomass-based diesel volume mandate to be treated as diesel volumes rather than as ethanol-equivalent volumes. Since all RINs are generated based on energy equivalency to ethanol, to accomplish this, we have modified the formula for calculating the standard for biomass-based diesel to compensate such that one physical gallon of biomass-based diesel will count as one gallon for purposes of meeting the biomass-based diesel standard, but will be counted based on their Equivalence Value for purposes of meeting the advanced biofuel and total renewable fuel standards. Since it is likely that the statutory volume mandates were based on projections for biodiesel, we have chosen to use the Equivalence Value for biodiesel, 1.5, in this calculation. See Section II.E.1.a for further discussion. Other diesel fuel made from renewable biomass can also qualify as biomass-based diesel (e.g., renewable diesel, cellulosic diesel). But since the variation in energy content between them is relatively small, variation in the total physical volume of biomass-based diesel will likewise be small.

In the NPRM we also proposed that the energy content of denatured ethanol be changed from the 77,550 Btu/gal value used in the RFS1 program to 77,930 Btu/gal (lower heating value). The revised value was intended to provide a more accurate estimate of the energy content of pure ethanol, 76,400 Btu/gal, rather than the rounded value of 76,000 Btu/gal that was used under RFS1. Except for the Renewable Fuels Association who supported this change, most stakeholders did not comment on this proposal. However, based on new provisions in the Food, Conservation, and Energy Act of 2008, we have since determined that the denaturant content of ethanol should be assumed to be 2% rather than the 5% used in the RFS1 program. This additional change results in a denatured ethanol energy content of 77,000 Btu/gal and a renewable content of denatured ethanol of 97.2%[11]. The value of 77,000 Btu/gal will be used to convert biogas and renewable electricity into volumes of renewable fuel under RFS2. This change also affects the formula for calculating Equivalence Values assigned to renewable fuels. The new formula is shown below:

[11] Value is lower than 98% because it is based on energy content of denaturant versus ethanol, not relative volume.

$$EV = (R / 0.972) * (EC / 77{,}000)$$

Where:

EV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.
R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from a renewable source, expressed as a percent, on an energy basis.
EC = Energy content of the renewable fuel, in Btu per gallon (lower heating value).

Under this new formula, Equivalence Values assigned to specific types of renewable fuel under RFS1 will continue unchanged under RFS2. However, non-ester renewable diesel will be required to have a lower energy content of at least 123,500 Btu/gal in order to qualify for an Equivalence Value of 1.7. A non-ester renewable diesel with a lower energy content would be required to apply for a different Equivalent Value according to the provisions in §80.1415.

2. Fuel Pathways and Assignment of D Codes

As described in Section II.A, RINs under RFS2 would in general continue to have the same number of digits and code definitions as under RFS1. The one change will be that, while the D code will continue to identify the standard to which the RIN can be applied, it will be modified to have four values corresponding to the four different renewable fuel categories defined in EISA. These four D code values and the corresponding categories are shown in Table II.A-1.

In order to generate RINs for renewable fuel that meets the various eligibility requirements (see Section II.B), a producer or importer must know which D code to assign to those RINs. Following the approach we described in the NPRM, a producer or importer will determine the appropriate D code using a lookup table in the regulations. The lookup table lists various combinations of fuel type, production process, and feedstock, and the producer or importer chooses the appropriate combination representing the fuel he is producing and for which he is generating RINs. Parties generating RINs are required to use the D code specified in the lookup table and are not permitted to use a D code representing a broader renewable fuel category. For example, a party whose fuel qualified as biomass-based diesel could not choose to categorize that fuel as advanced biofuel or general renewable fuel for purposes of RIN generation[12].

This section describes our approach to the assignment of D codes to RINs for domestic producers, foreign producers, and importers of renewable fuel. Subsequent sections address the generation of RINs in special circumstances, such as when a production facility has multiple applicable combinations of feedstock, fuel type, and production process within a calendar year, production facilities that co-process renewable biomass and fossil fuels, and production facilities for which the lookup table does not provide an applicable D code.

[12] However, a biomass-based diesel RIN can be used to satisfy Renewable Volume Obligations (RVO) for biomass-based diesel, advanced biofuel, and total renewable fuel. See Section II.G.3 for further discussion of the use of RINs for compliance purposes.

a. Producers

For both domestic and foreign producers of renewable fuel, the lookup table identifies individual fuel "pathways" comprised of unique combinations of the type of renewable fuel being produced, the feedstock used to produce the renewable fuel, and a description of the production process. Each pathway is assigned to one of the D codes on the basis of the revised renewable fuel definitions provided in EISA and our assessment of the GHG lifecycle performance for that pathway. A description of the lifecycle assessment of each fuel pathway and the process we used for determining the associated D code can be found in Section V.

Note that the generation of RINs also requires as a prerequisite that the feedstocks used to make the renewable fuel meet the definition of "renewable biomass" as described in Section II.B.4, including applicable land use restrictions. If a producer is not able to demonstrate that his feedstocks meet the definition of renewable biomass, RINs cannot be generated. However, as noted in Section II.B.4.b.1, feedstocks typically include incidental contaminants. These contaminants may have been intentionally added to promote cultivation (e.g., pesticides, herbicides, fertilizer) or transport (e.g., nylon baling rope). In addition, there may be some incidental contamination of a particular load of feedstocks with co-product during feedstock production, or with other agricultural materials during shipping. For example, there may be incidental corn kernels remaining on some corn cobs used to produce cellulosic biofuel, or some sorghum kernels left in a shipping container that are introduced into a load of corn kernels being shipped to a biofuel production facility. The final regulations clarify that in assigning D codes for renewable fuel, producers and importers should disregard the presence of incidental contaminants in their feedstocks if the incidental contaminants are related to customary feedstock production and transport, and are impractical to remove and occur in de minimus levels.

Through our assessment of the lifecycle GHG impacts of different pathways and the application of the EISA definitions for each of the four categories of renewable fuel, including the GHG thresholds, we have determined that all four categories will have pathways that could be used to meet the Act's volume requirements. For example, ethanol made from corn stover or switchgrass in an enzymatic hydrolysis process will count as cellulosic biofuel. Biodiesel made from waste grease or soybean oil can count as biomass-based diesel. Ethanol made from sugarcane sugar will count as advanced biofuel. Finally, a variety of pathways will count as renewable fuel under the RFS2 program. The complete list of pathways that are valid under our final RFS2 program is discussed in Section V.C and are provided in the regulations at §80.1426(f).

Producers must choose the appropriate D code from the lookup table in the regulations based on the fuel pathway that describes their facility. The fuel pathway must be specified by the producer in the registration process as described in Section II.C. If there are changes to a producer's facility or feedstock such that their fuel would require a D code that was different from any D code(s) which their existing registration information already allowed, the producer is required to revise its registration information with EPA 30 days prior to changing the applicable D code it uses to generate RINs. Situations in which multiple fuel pathways could apply to a single facility are addressed in Section II.D.3 below.

For producers for whom none of the defined fuel pathways in the lookup table apply, a producer can still generate RINs if he meets the criteria for grandfathered or deemed compliant status as described in Section II.B.3 and his fuel meets the definition of renewable fuel as described in Section II.B.1. In this case he would use a D code of 6 for those RINs generated under the grandfathering or deemed compliant provisions.

A diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold can qualify as either cellulosic biofuel or biomass-based diesel. In the NPRM, we proposed that the producer of such "cellulosic diesel" be required to choose whether to categorize his product as either cellulosic biofuel or biomass-based diesel. However, we requested comment on an alternative approach in which an additional D code would be defined to represent cellulosic diesel allowing the cellulosic diesel RIN to be sold into either market. As described more fully in Section II.A above, we are finalizing this alternative approach in today's final rule. Producers or importers of a fuel that qualifies as both biomass-based diesel and cellulosic biofuel must use a D code of 7 in the RINs they generate, and will thus have the flexibility of marketing such RINs to parties seeking either cellulosic biofuel or biomass-based diesel RINs, depending on market demand. Obligated parties can apply RINs with a D code of 7 to either their cellulosic biofuel or biomass-based diesel RVOs, but not both.

In addition to the above comments, we received comments requesting that the use of biogas as process heat in the production of ethanol, should not be limited to use at the site of renewable fuel production. Specifically, commenters point out that the introduction of gas produced from landfills or animal wastes to fungible pipelines is the only practical manner for most renewable fuel facilities to acquire and use landfill gas, since very few are located adjacent to landfills, or have dedicated pipelines from landfill gas operations to their facilities.[13] The commenters suggested that ethanol plants causing landfill gas to be introduced into a fungible gas pipeline be allowed to claim those volumes. The alternative would be to allow landfill gas that is only used onsite to be counted in establishing the pathway.

We believe that the suggested approach has merit. We agree that it does not make any difference in terms of the beneficial environmental attributes associated with the use of landfill gas whether the displacement of fossil fuel occurs in a fungible natural gas pipeline, or in a specific facility that draws gas volume from that pipeline. In fact, a similar approach is widely used with respect to electricity generated by renewable biomass that is placed into a commercial electricity grid. A party buying the renewable power is credited with doing so in state renewable portfolio programs even though the power from these sources is placed in the fungible grid and the electrons produced by a renewable source may never actually be used by the party purchasing it. In essence these programs assume that the renewable power purchased and introduced into the grid is in fact used by the purchaser, even though all parties acknowledge that use of the actual renewable-derived electrons can never be verified once placed in the fungible grid**.** We believe that this approach will ultimately further the GHG reduction and energy security goals of RFS2.

[13] This suggestion was also made by several companies with respect to the RFS1 definition of cellulosic biomass ethanol, which allowed corn-based ethanol to be deemed cellulosic if 90% of the fossil fuel used at the ethanol facility to make ethanol was displaced by fuel derived from animal or other waste materials, including landfill gas.

Producers may therefore take into account such displacement provided that they demonstrate that a verifiable contractual pathway exists and that such pathway ensures that 1) a specific volume of landfill gas was placed into a commercial pipeline that ultimately serves the transportation fueling facility and 2) that the drawn into this facility from that pipeline matches the volume of landfill gas placed into the pipeline system. Thus facilities using such a fuel pathway may then use an appropriate D code for generation of RINs.

This approach also applies to biogas and electricity made from renewable fuels and which are used for transportation. Producers of such fuel will be able to generate RINs, provided that a contractual pathway exists that provides evidence that specific quantities of the renewable fuel (either biogas or electricity) was purchased and contracted to be delivered to a specific transportation fueling facility.[14] We specify that the pipeline (or transmission line) system must ultimately serve the subject facility. For electricity that is produced by the co-firing of fossil fuels with renewable biomass derived fuels, we are requiring that the resulting electricity is pro-rated to represent only that amount of electricity generated by the qualifying biogas, for the purpose of computing RINs.

We are also providing for those situations in which biogas or renewable electricity is provided directly to the transportation facility, rather than using a commercial distribution system such as pipelines or transmission lines. For both cases—dedicated use and commercial distribution—producers must provide contractual evidence of the production and sale of such fuel, and there are also reporting and recordkeeping requirements to be followed as well.

Presently, there is no D code for electricity that is produced from renewable biomass. The petition process for assigning such codes in today's rule can be used for such purpose.

b. Importers

For imported renewable fuel under RFS2, we are anticipating the importer to be the primary party responsible for generating RINs. However, the foreign producer of renewable fuel can instead elect to generate RINs themselves under certain conditions as described more fully in Section II.D.2.c below. This approach is consistent with the approach under RFS1.

Under RFS1, importers who import more than 10,000 gallons in a calendar year were required to generate RINs for all imported renewable fuel based on its type, except for cases in which the foreign producer generated RINs for cellulosic biomass ethanol or waste-derived ethanol. Due to the new definitions of renewable fuel and renewable biomass in EISA, importers can no longer generate RINs under RFS2 on the basis of fuel type alone. Instead, they must be able to demonstrate that the renewable biomass definition has been met for the renewable fuel they intend to import and for which they will generate RINs. They must also have sufficient information about the feedstock and process used to make the renewable fuel to allow them to identify the appropriate D code from the lookup table for the RINs they generate. Therefore, in order to generate RINs, the importer will be required to obtain this information from a foreign

[14] Note that biogas used for transportation fuel includes propane made from renewable biomass.

producer. RINs can only be generated if a demonstration is made that the feedstocks used to produce the renewable fuel meet the definition of renewable biomass.

In summary, under today's final rule, importers can import any renewable fuel, but can only generate RINs to represent the imported renewable fuel under the two conditions described below. If these conditions do not apply, the importer can import biofuel but cannot generate RINs to represent that biofuel.

1. The imported renewable fuel is not accompanied by RINs generated by the registered foreign producer

2. The importer obtains from the foreign producer:

   - Documentation demonstrating that the renewable biomass definition has been met for the volume of renewable fuel being imported.

   - Documentation about the feedstock and production process used to produce the renewable fuel to allow the importer to determine the appropriate D-code designation in the RINs generated

We are also finalizing additional requirements for foreign producers who either generate RINs or provide documentation to an importer sufficient to allow the importer to generate RINs. As described more fully in the next section, these additional requirements include restrictions on mixing of biofuels in the distribution system as it travels from the foreign producer to the importer.

Finally, EPA is assessing whether additional requirements on foreign-generated fuel may be necessary for situations in which importers are generating RINs for the fuel. Additional requirements may be necessary to ensure that the importers have sufficient information to properly generate the RINs and that EPA has sufficient information to determine whether those RINs have been legitimately generated. EPA will pursue an amendment to the final RFS2 regulations if we find that additional requirements are appropriate and necessary.

c. Additional Provisions for Foreign Producers

In general, we are requiring foreign producers of renewable fuel to meet the same requirements as domestic producers with respect to registration, recordkeeping and reporting, attest engagements, and the transfer of RINs they generate with the batches of renewable fuel that those RINs represent. However, we are also placing additional requirements on foreign producers to ensure that RINs entering the U.S. are valid and that the regulations can be enforced at foreign facilities. These additional requirements are designed to accommodate the more limited access that EPA enforcement personnel have to foreign entities that are regulated parties under RFS2, and also the fact that foreign-produced biofuel intended for export to the U.S. is often mixed with biofuel that will not be exported to the U.S.

Under RFS1, foreign producers had the option of generating RINs for the renewable fuel that they export to the U.S. if they wanted to designate their fuel as cellulosic biomass ethanol or waste-derived ethanol, and thereby take advantage of the additional 1.5 credit value afforded by the 2.5 Equivalence Value for such products. In order to ensure that EPA had the ability to enforce the regulations relating to the generation of RINs from such foreign ethanol producers, the RFS1 regulations specified additional requirements for them, including posting a bond, admitting EPA enforcement personnel, and submitting to third-party engineering reviews of their production process. For RFS2, we are maintaining these additional requirements for foreign producers because EPA enforcement personnel have the same limitations under RFS2 with regard to access to foreign entities that are regulated parties as they did under RFS1.

EISA also creates other unique challenges in the implementation and enforcement of the renewable fuel standards for foreign-produced renewable fuel imported into the U.S. Unlike our other fuels programs, EPA cannot determine whether a particular shipment of renewable fuel is eligible to generate RINs under the new program by testing the fuel itself. Instead, information regarding the feedstock that was used to produce renewable fuel and the process by which it was produced is vital to determining the proper renewable fuel category and RIN type for the imported fuel under the RFS2 program. Thus, whether foreign producers or importers generate RINs, this information must be collected and maintained by the RIN generator.

If a foreign producer generates RINs for renewable fuel that it produces and exports to the U.S., we are requiring that ethanol must be dewatered and denatured by the foreign producer prior to leaving the production facility and prior to the generation of RINs. This is consistent with our definition of renewable fuel in which ethanol that is valid under RFS2 must be denatured. Moreover, the foreign producer is required to strictly segregate a batch of renewable fuel and its associated RINs from all other volumes of renewable fuel as it travels from the foreign producer to the importer. The strict segregation ensures that RINs entering the U.S. appropriately represent the renewable fuel imported into the U.S. both in terms of renewable fuel type and volume.

Several commenters requested that in general the importer be the RIN generator for imported renewable fuel. Since most imported ethanol is currently made in Brazil and is not denatured by the foreign producer, any RINs generated must be generated by the importer. However, to accomplish this, the importer must obtain the appropriate information from a foreign producer regarding compliance with the renewable biomass definition and a description of the associated pathway for the renewable fuel. Under these circumstances, the foreign producer must ensure that the information is transferred along with the renewable fuel through the distribution system until it reaches the importer. The foreign producer's volume of renewable fuel need not be strictly segregated from other volumes in this case, so long as a volume of chemically indistinguishable renewable fuel is tracked through the distribution system from the foreign producer to the importer, and the information needed by the importer to generate RINs follows this same path through the distribution system. Strict segregation of the volume is not necessary in this case, and the importer will determine appropriate number of RINs for the specific volume and type of renewable fuel that he imports.

Finally, if a foreign producer chooses not to participate in the RFS2 program and thus neither generates RINs nor provides information to the importer so that the importer can generate RINs, the foreign producer can still export biofuel to the U.S. However, under these circumstances the biofuel would not be renewable fuel under RFS2, no RINs could be generated by any party, and thus the foreign producer would not be subject to any of the registration, recordkeeping, reporting, or attest engagement requirements.

3. Facilities With Multiple Applicable Pathways

If a given facility's operations can be fully represented by a single pathway, then a single D code taken from the lookup table will be applicable to all RINs generated for fuel produced at that facility. However, we recognize that this will not always be the case. Some facilities use multiple feedstocks at the same time, or switch between different feedstocks over the course of a year. A facility may be modified to produce the same fuel but with a different process, or may be modified to produce a different type of fuel. Any of these situations could result in multiple pathways being applicable to a facility, and thus there may be more than one applicable D code for various RINs generated at the facility.

If more than one pathway applies to a facility within a compliance period, no special steps will need to be taken if the D code is the same for all the applicable pathways. In this case, all RINs generated at the facility will have the same D code regardless. Such a producer with multiple applicable pathways must still describe its feedstock(s), fuel type(s), and production process(es) in its initial registration and annual report to the Agency so that we can verify that the D code used was appropriate.

However, if more than one pathway applies to a facility within a compliance period and these pathways have been assigned different D codes, then the producer must determine which D codes to use when generating RINs. There are a number of different ways that this could occur. For instance, a producer could change feedstocks, production processes, or the type of fuel he produces in the middle of a compliance period. Or, he could use more than one feedstock or produce more than one fuel type simultaneously. The approach we are finalizing for designating D codes for RINs in these cases follows the approach described in the NPRM and is summarized in Table II.D.3-1.

Table II.D.3-1
Approach to Assigning Multiple D Codes for Multiple Applicable Pathways

Case	Description	Proposed approach
1	The pathway applicable to a facility changes on a specific date, such that one single pathway applies before the date and another single pathway applies on and after the date.	The applicable D code used in generating RINs must change on the date that the fuel produced changes pathways.
2	One facility produces two or more different types of renewable fuel at the same time.	The volumes of the different types of renewable fuel should be measured separately, with different D codes applied to the separate volumes.
3	One facility uses two or more different feedstocks at the same time to produce a single type of renewable fuel.	For any given batch of renewable fuel, the producer should assign the applicable D codes using a ratio (explained below) defined by the amount of each type of feedstock used.

Commenters were generally supportive of this approach to multiple applicable pathways, and as a result we are finalizing it with few modifications from the proposal. Further discussion of the comments we received can be found in Section 3.5.4 of the S&A document.

Following our proposal, cases listed in Table II.D.3-1 will be treated as hierarchical, with Case 2 only being used to address a facility's circumstances if Case 1 is not applicable, and Case 3 only being used to address a facility's circumstances if Case 2 is not applicable. This approach covers all likely cases in which multiple applicable pathways may apply to a renewable fuel producer. Some examples of how Case 2 or 3 would apply are provided in the NPRM.

A facility where two or more different types of feedstock are used to produce a single fuel (such as Case 3 in Table II.D.3-1) will be required to generate two or more separate batch-RINs[15] for a single volume of renewable fuel, and these separate batch-RINs will have different D codes. The D codes will be chosen on the basis of the different pathways as defined in the lookup table in §80.1426(f). The number of gallon-RINs that will be included in each of the batch-RINs will depend on the relative amount of the different types of feedstocks used by the facility. In the NPRM, we proposed to use the relative energy content of the feedstocks to determine how many gallon-RINs should be assigned to each D code. Commenters generally did not address this aspect of our proposal, and we are finalizing it in today's action. Thus, the useable energy content of each feedstock must be used to divide the total number of gallon-RINs generated for a batch of renewable fuel into two or more groups, each corresponding to a different D code. Several separate batch-RINs can then be generated and assigned to the single volume of renewable fuel. The applicable calculations are given in the regulations at §80.1426(f)(3).

[15] Batch-RINs and gallon-RINs are defined in the regulations at 40 CFR 80.1401.

We proposed several elements of the calculation of the useable energy content of the feedstocks, including the following:

1. Only that fraction of a feedstock which is expected to be converted into renewable fuel by the facility can be counted in the calculation, taking into account facility conversion efficiency.

2. The producer of the renewable fuel is required to designate this fraction once each year for the feedstocks processed by his facility during that year, and to include this information as part of his reporting requirements.

3. Each producer is required to designate the energy content (in Btu/lb) once each year of the portion of each of his feedstocks which is converted into fuel. The producer may determine these values for his own feedstocks, or may use default values provided in the regulations at §80.1426(f)(7).

4. Each producer is required to determine the total mass of each type of feedstock used by the facility on at least a daily basis.

Based on the paucity of comments we received on this issue, we are finalizing the provisions regarding the calculation of useable energy content of the feedstocks as it was proposed in the NPRM. As described in Section II.J, producers of renewable fuel will be required to submit information in their reports on the feedstocks they used, their production processes, and the type of fuel(s) they produced during the compliance period. This will apply to both domestic producers and foreign producers who export any renewable fuel to the U.S. We will use this information to verify that the D codes used in generating RINs were appropriate.

4. Facilities that Co-Process Renewable Biomass and Fossil Fuels

We expect situations to arise in which a producer uses a renewable feedstock simultaneously with a fossil fuel feedstock, producing a single fuel that is only partially renewable. For instance, biomass might be co-fired with coal in a coal-to-liquids (CTL) process that uses Fischer-Tropsch chemistry to make diesel fuel, biomass and waste plastics might be fed simultaneously into a catalytic or gasification process to make diesel fuel, or vegetable oils could be fed to a hydrotreater along with petroleum to produce a diesel fuel. In these cases, the diesel fuel will be only partially renewable. RINs can be generated in such cases, but must be done in such a way that the number of gallon-RINs corresponds only to the renewable portion of the fuel.

Under RFS1, we created a provision to address the co-processing of "renewable crudes" along with petroleum feedstocks to produce a gasoline or diesel fuel that is partially renewable. See 40 CFR 80.1126(d)(6). However, this provision would not apply in cases where either the renewable feedstock or the fossil fuel feedstock is a gas (e.g., biogas, natural gas) or a solid (e.g., biomass, coal). Therefore, we are eliminating the RFS1 provision applicable only to liquid feedstocks and replacing it with a more comprehensive approach that will apply to liquid, solid, or gaseous feedstocks and any type of conversion process. In this final approach, producers are required to use the relative energy content of their renewable and non-renewable feedstocks to determine the renewable fraction of the fuel that they produce. This fraction in turn is used to determine the number of gallon-RINs that should be generated for each batch. Commenters said little about our proposed methodology to use the relative energy content of the feedstocks, and we are therefore finalizing it largely as proposed.

We also requested comment on allowing renewable fuel producers to use an accepted test method to directly measure the fraction of the fuel that is derived from biomass rather than a fossil fuel feedstock. For instance, ASTM D-6866 is a radiocarbon dating test method that can be used to determine the renewable content of transportation fuel. The use of such a test method can be used in lieu of the calculation of the renewable portion of the fuel based on the relative energy content of the renewable biomass and fossil feedstocks. Commenters generally supported the option of using a radiocarbon dating approach. As a result, we believe it would be appropriate and are finalizing a provision to allow parties that co-process renewable biomass and fossil fuels to choose between using the relative energy in the feedstocks or ASTM D-6866 to determine the number of gallon-RINs that should be generated. Regardless of the approach chosen, the producer will still need to separately verify that the renewable feedstocks meet the definition of renewable biomass.

If a producer chose to use the energy content of the feedstocks, the calculation would be similar to the treatment of renewable fuels with multiple D codes as described in Section II.D.3 above. As shown in the regulations at §80.1426(f)(3), the producer would determine the renewable fuel volume that would be assigned RINs based on the amount of energy in the renewable feedstock relative to the amount of energy in the fossil feedstock. Only one batch-RIN would be generated for a single volume of fuel produced from both a renewable feedstock and a fossil feedstock, and this one batch-RIN must be based on the contribution that the renewable feedstock makes to the total volume of fuel. The calculation of the relative energy contents includes factors that take into account the conversion efficiency of the plant, and as a result potentially different reaction rates and byproduct formation for the various feedstocks will be accounted for. The relative energy content of the feedstocks is used to adjust the basic calculation of the number of gallon-RINs downward from that calculated on the basis of batch fuel volume and the applicable Equivalence Value. The D code that must be assigned to the RINs is drawn from the lookup table in the regulations as if the feedstock was entirely renewable biomass. Thus, for instance, a coal-to-liquids plant that co-processes some cellulosic biomass to make diesel fuel would be treated as a plant that produces only cellulosic diesel for purposes of identifying the appropriate D code for the fraction of biofuel that qualifies as renewable fuel under EISA.

If a producer chose to use D-6866, he would be required to either apply this test to every batch, or alternatively to take samples of every batch of fuel he produced over the course of one month and combine them into a single composite sample. The D-6866 test would then be applied to the composite sample, and the resulting renewable fraction would be applied to all batches of fuel produced in the next month to determine the appropriate number of RINs that must be generated. For the first month, the producer can estimate the non-fossil fraction, and then make a correction as needed in the second month. The producer would be required to recalculate the renewable fraction every subsequent month. See the regulations at §80.1426(f)(9).

5. Facilities that Process Municipal Solid Waste

As described in Section II.B.4.d, only the separated yard and food waste of municipal solid waste (MSW) are considered to be renewable biomass and may be used to produce renewable fuels under the RFS2 program. While renewable fuel producers may produce fuel from all organic components of MSW, they may generate RINs for only that portion of MSW that qualifies as renewable biomass. We are providing two methods for determining the appropriate number of RINs to generate for each batch of fuel, depending on whether the feedstock is pure food and yard waste, or separated municipal solid waste, as described in Section II.B.4.d. While not all biogenic material in the separated MSW is cellulosic, the vast majority of it is likely to be in most situations. Specifically, separated municipal solid waste may contain some non-biogenic materials such as plastics that were unable to be recycled due to market conditions. We are requiring producers of renewable fuel made from separated municipal solid waste to use the radiocarbon dating method D-6866 to calculate the biogenic fraction, presumed to be composed of cellulosic materials. Therefore, unless a renewable fuel producer is using MSW streams that are clearly not cellulosic, we anticipate that a D code of either 3 or 7 will be appropriate for such RINs. See the regulations at §80.1426(f).

6. RINless Biofuel

Under the RFS1 program, all renewable fuel made from renewable feedstocks and used as motor vehicle fuel in the U.S. was assigned RINs. Therefore, aside from the very small amounts of biofuel used in nonroad applications or as heating oil, all renewable fuel produced or imported counted towards the mandated volume goals of the RFS program. Although conventional diesel fuel was not subject to the standards under RFS1, all other motor vehicle fuel fell into two groups: fuel subject to the standards, and fuel for which RINs were generated and was used to meet those standards.

Under RFS2, our approach to compliance with the renewable biomass provision will allow the possibility for some biofuel to be produced without RINs. As described in Section II.B.4 above, we are modifying our approach to compliance with the renewable biomass provision so that renewable fuel producers using feedstocks from domestic planted crops and crop residue will be presumed to meet the renewable biomass provision. Under this "aggregate compliance" approach, these producers will be generating RINs for all their renewable fuel. However, producers who use foreign-grown crops or crop residue or other feedstocks such as planted trees or forestry residues will not be able to take advantage of this aggregate compliance approach. Instead, they will be required to demonstrate that their feedstocks meet the renewable biomass definition, including the associated land use restrictions, before they will be permitted to generate RINs. Absent such a demonstration, these producers can still produce biofuel but will not generate RINs. In addition, fuel producers whose fuel does not qualify as renewable fuel under this program because it does not meet the 20% GHG threshold (and is not grandfathered) can still produce biofuel but will not be allowed to generate RINs. Transportation fuel consumed in the U.S. will therefore be comprised of three groups: fuel subject to the standards (gasoline and diesel), fuel for which RINs are generated and will be used to meet those standards, and RINless biofuel. RINless biofuel will not be covered under any aspect of the RFS2 program, despite the fact that in many cases it will meet the EISA definition of transportation fuel upon blending with gasoline or diesel.

In their comments in response to the NPRM, several refiners suggested that RINless biofuel should be treated as an obligated volume similar to gasoline and diesel, and thus be subject to the standards. Doing so would ensure that all transportation fuels are covered under the RFS2 program, consistent with RFS1. Such an approach would also provide renewable fuel producers with an incentive to demonstrate that their feedstocks meet the renewable biomass definition and thus generate RINs for all the biofuel that they produce. There could be less potential for market manipulation on the part of biofuel producers who might be considering producing RINless biofuel as a means for increasing demand for renewable fuel and RINs.

Nevertheless, we do not believe that it would be appropriate at this time to finalize a requirement that RINless biofuel be considered an obligated fuel subject to the standards. We did not propose such an approach in the NPRM, and as a result many renewable fuel producers who could be affected did not have an opportunity to consider and comment on it. Moreover, the volume of RINless biofuel is likely to be small compared to the volume of renewable fuel with RINs since RINs have value and producers currently have an incentive to generate them. However, if in the future RIN values should fall - for instance, if crude oil prices rise high enough and the market drives up demand for biofuels - the incentive to demonstrate compliance with the renewable biomass definition may decrease and there may be an increase in the volume of RINless biofuel. Under such circumstances it may be appropriate to reconsider whether RINless biofuel should be designated as an obligated volume subject to the standards.

E. Applicable Standards

The renewable fuel standards are expressed as a volume percentage, and are used by each refiner, blender or importer to determine their renewable fuel volume obligations. The applicable percentages are set so that if each regulated party meets the percentages, then the amount of renewable fuel, cellulosic biofuel, biomass-based diesel, and advanced biofuel used will meet the volumes specified in Table I.A.1-1.[16]

The formulas finalized today for use in deriving annual renewable fuel standards are based in part on an estimate of combined gasoline and diesel volumes, for both highway and nonroad uses, for the year in which the standards will apply. The standards will apply to refiners, blenders, and importers of these fuels. As described more fully in Section II.F.3, other producers of transportation fuel, such as producers of natural gas, propane, and electricity from fossil fuels, are not subject to the standards. Since the standards apply to refiners, blenders and importers of gasoline and diesel, these are also the transportation fuels that are used to determine the annual volume obligations of an individual refiner, blender, or importer.

[16] Actual volumes can vary from the amounts required in the statute. For instance, lower volumes may result if the statutorily required volumes are adjusted downward according to the waiver provisions in CAA 211(o)(7)(D). Also, higher or lower volumes may result depending on the actual consumption of gasoline and diesel in comparison to the projected volumes used to set the standards.

The projected volumes of gasoline and diesel used to calculate the standards will continue to be provided by EIA's Short-Term Energy Outlook (STEO). The standards applicable to a given calendar year will be published by November 30 of the previous year. Gasoline and diesel volumes will continue to be adjusted to account for the required renewable fuel volumes. In addition, gasoline and diesel volumes produced by small refineries and small refiners will be exempt through 2010, and that year's standard is adjusted accordingly, as discussed below.

As discussed in the proposal, four separate standards are required under the RFS2 program, corresponding to the four separate volume requirements shown in Table I.A.1-1. The specific formulas we use to calculate the renewable fuel standards are described below in Section II.E.1.

In order for an obligated party to demonstrate compliance, the percentage standards are converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and continues to be referred to as its Renewable Volume Obligation (RVO). Since there are four separate standards under the RFS2 program, there are likewise four separate RVOs applicable to each obligated party. Each standard applies to the sum of all gasoline and diesel produced or imported. Determination of RVOs is discussed in Section II.G.2.

1. Calculation of Standards

a. How Are the Standards Calculated?

The four separate renewable fuel standards are based primarily on (1) the 49-state[17] gasoline and diesel consumption volumes projected by EIA, and (2) the total volume of renewable fuels required by EISA for the coming year. Table I.A.2-1 shows the required overall volumes of four types of renewable fuel specified in EISA. Each renewable fuel standard is expressed as a volume percentage of combined gasoline and diesel sold or introduced into commerce in the U.S., and is used by each obligated party to determine its renewable volume obligation.

Today we are finalizing an approach to setting standards that is based in part on the sum of all gasoline and diesel produced or imported in the 48 contiguous states and Hawaii. An approach we are not adopting but which we discussed in the proposal would have split the standards between those that would be specific to gasoline and those that would be specific to diesel. Though this approach to setting standards would more readily align the RFS obligations with the relative amounts of gasoline and diesel produced or imported by each obligated party, we are not adopting this approach because it relies on projections of the relative amounts of gasoline-displacing and diesel-displacing renewable fuels. These projections would need to be updated every year, and as stated in the proposal, we believe that such an approach would unnecessarily complicate the program.

While the required amount of total renewable fuel for a given year is provided by EISA, the Act requires EPA to base the standards on an EIA estimate of the amount of gasoline and

[17] Hawaii opted-in to the original RFS program; that opt-in is carried forward to this program.

diesel that will be sold or introduced into commerce for that year. As discussed in the proposal, EIA's STEO will continue to be the source for projected gasoline, and now diesel, consumption estimates. In order to achieve the volumes of renewable fuels specified in EISA, the gasoline and diesel volumes used to determine the standard must be the non-renewable portion of the gasoline and diesel pools. Because the STEO volumes include renewable fuel use, we must subtract the total renewable fuel volume from the total gasoline and diesel volume to get total non-renewable gasoline and diesel volumes. The Act also requires EPA to use EIA estimates of renewable fuel volumes; the best estimation of the coming year's renewable fuel consumption is found in Table 8 (U.S. Renewable Energy Supply and Consumption) of the STEO. Additional information on projected renewable fuel use will be included as it becomes available.

As discussed in Section II.D.1, we are finalizing the energy content approach to Equivalence Values for the cellulosic biofuel, advanced biofuel, and total renewable fuel standards. However, the biomass-based diesel standard is based on the volume of biodiesel. In order to align both of these approaches simultaneously, biodiesel will continue to generate 1.5 RINs per gallon as in RFS1, and the biomass-based diesel volume mandate from EISA is then adjusted upward by the same 1.5 factor. The net result is a biomass-based diesel gallon being worth 1.0 gallons toward the biomass-based diesel standard, but 1.5 gallons toward the other standards.

CAA section 211(o) exempts small refineries[18] from the RFS requirements until the 2011 compliance period. In RFS1, we extended this exemption to the few remaining small refiners not already exempted.[19] Small refineries and small refiners will continue to be exempt from the program until 2011 under the new RFS2 regulations. Thus we have excluded their gasoline and diesel volumes from the overall non-renewable gasoline and diesel volumes used to determine the applicable percentages until 2011. As discussed in the proposal, total small refinery and small refiner gasoline production volume is expected to be fairly constant compared to total U.S. transportation fuel production. Thus we estimated small refinery and small refiner gasoline and diesel volumes using a constant percentage of national consumption, as we did in RFS1. Using information from gasoline batch reports submitted to EPA for 2006, EIA data, and input from the California Air Resources Board regarding California small refiners, we estimate that small refinery volumes constitute 11.9% of the gasoline pool, and 15.2% of the diesel pool.

CAA section 211(o) requires that the small refinery adjustment also account for renewable fuels used during the prior year by small refineries that are exempt and do not participate in the RFS2 program. Accounting for this volume of renewable fuel would reduce the total volume of renewable fuel use required of others, and thus directionally would reduce the percentage standards. However, as we discussed in RFS1, the amount of renewable fuel that would qualify, i.e., that was used by exempt small refineries and small refiners but not used as part of the RFS program, is expected to be very small. In fact, these volumes would not significantly change the resulting percentage standards. Whatever renewable fuels small refineries and small refiners blend will be reflected as RINs available in the market; thus there is

[18] Under section 211(o) of the Clean Air Act, small refineries are those with 75,000 bbl/day or less average aggregate daily crude oil throughput.
[19] See Section III.E.

no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We proposed and are finalizing this value as zero.

The levels of the percentage standards would be reduced if Alaska or a U.S. territory chooses to participate in the RFS2 program, as gasoline and diesel produced in or imported into that state or territory would then be subject to the standard. Section 211(o) of the Clean Air Act requires that the renewable fuel be consumed in the contiguous 48 states, and any other state or territory that opts-in to the program (Hawaii has subsequently opted in). However, because renewable fuel produced in Alaska or a U.S. territory is unlikely to be transported to the contiguous 48 states or to Hawaii, including their renewable fuel volumes in the calculation of the standard would not serve the purpose intended by section 211(o) of the Clean Air Act of ensuring that the statutorily required renewable fuel volumes are consumed in the 48 contiguous states and any state or territory that opts-in. Therefore, renewable fuels used in Alaska or U.S. territories are not included in the renewable fuel volumes that are subtracted from the total gasoline and diesel volume estimates.

In summary, the total projected non-renewable gasoline and diesel volumes from which the annual standards are calculated are based on EIA projections of gasoline and diesel consumption in the contiguous 48 states and Hawaii, adjusted by constant percentages of 11.9% and 15.2% in 2010 to account for small refinery/refiner gasoline and diesel volumes, respectively, and with built-in correction factors to be used when and if Alaska or a territory opt-in to the program.

The following formulas are used to calculate the percentage standards:

$$\mathrm{Std}_{\mathrm{CB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{CB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{BBD,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{BBD,\,i}} \times 1.5}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{AB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{AB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{RF,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{RF,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

Where

$\mathrm{Std}_{\mathrm{CB,i}}$ = The cellulosic biofuel standard for year i, in percent

$\mathrm{Std}_{\mathrm{BBD,i}}$ = The biomass-based diesel standard (ethanol-equivalent basis) for year i, in percent

$\mathrm{Std}_{\mathrm{AB,i}}$ = The advanced biofuel standard for year i, in percent

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{RF,i}$ = Annual volume of renewable fuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

G_i = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons*

D_i = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons

RG_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

RD_i = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

GS_i = Amount of gasoline projected to be used in Alaska or a U.S. territory in year i if the state or territory opts-in, in gallons*

RGS_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska or a U.S. territory in year i if the state or territory opts-in, in gallons

DS_i = Amount of diesel projected to be used in Alaska or a U.S. territory in year i if the state or territory opts-in, in gallons*

RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory in year i if the state or territory opts-in, in gallons

GE_i = The amount of gasoline projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§80.1441 and 80.1442, respectively. Equivalent to $0.119*(G_i-RG_i)$.

DE_i = The amount of diesel projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§80.1441 and 80.1442, respectively. Equivalent to $0.152*(D_i-RD_i)$.

*	Note that these terms for projected volumes of gasoline and diesel use include gasoline and diesel that has been blended with renewable fuel.

b.	Standards for 2010

We are finalizing the standards for 2010 in today's action. As explained in Section I.A.2, while the rulemaking is not effective until July 1, 2010, the 2010 standards we are setting are annual standards with compliance demonstrations are due by February 28, 2011.

Under CAA section 211(o)(7)(D)(i), EPA is required to make a determination each year regarding whether the required volumes of cellulosic biofuel for the following year can be produced. For any calendar year for which the projected volume of cellulosic biofuel production is less than the minimum required volume, the projected volume becomes the basis for the cellulosic biofuel standard. In such a case, the statute also indicates that EPA may also lower the required volumes for advanced biofuel and total renewable fuel.

As discussed in Section IV.B., we are utilizing the EIA projection of 5.04 million gallons (6.5 million ethanol equivalent gallons) of cellulosic biofuel as the basis for setting the percentage standard for cellulosic biofuel for 2010. This is lower than the 100 million gallon standard set by EISA that we proposed upholding, but reflects the current state of the industry, as discussed in section V.B. We expect continued growth in the industry in 2011 and beyond. Since the advanced biofuel standard is met by just the biomass-based diesel volume required in 2010, and additional volumes of other advanced biofuels (e.g., sugarcane ethanol) are available as well, no change to the advanced biofuel standard is necessary for 2010. Moreover, given the nested nature of the volume mandates, since no change in the advanced biofuel standard is necessary, the total renewable fuel standard need not be changed either.

Table II.E.1.b-1
Standards for 2010

Cellulosic biofuel	0.004%
Biomass-based diesel	1.10%
Advanced biofuel	0.61%
Renewable fuel	8.25%

2.	<u>Treatment of Biomass-Based Diesel in 2009 and 2010</u>

As described in Section I.A.2, the four separate 2010 standards issued in today's rule will apply to all gasoline and diesel produced in 2010. However, EISA included volume mandates for biomass-based diesel, advanced biofuel, and total renewable fuel that applied in 2009. Since the RFS2 program was not effective in 2009 and thus the volume mandates for biomass-based diesel and advanced biofuel were not implemented in 2009, our NPRM proposed a mechanism to ensure that the 2009 biomass-based diesel volume mandate would eventually be met. In today's final rule we are finalizing the proposed approach.

a. Shift in 2009 Biomass-Based Diesel Compliance Demonstration to 2010

Under the RFS1 regulations that applied in 2009, we set the applicable standard for total renewable fuel in November 2008[20] using the required volume of 11.1 billion gallons specified in the Clean Air Act (as amended by EISA), gasoline volume projections from EIA, and the formula provided in the regulations at §80.1105(d). The existing RFS1 regulations did not provide a mechanism for requiring the use of 0.5 billion gallons of biomass-based diesel or the 0.6 billion gallons of advanced biofuel mandated by EISA for 2009.

In the NPRM we proposed that the compliance demonstration for the 2009 biomass-based diesel requirement of 0.5 bill gal be extended to 2010. This approach would combine the 0.5 bill gal requirement for 2009 and the 0.65 bill gal requirement for 2010 into a single requirement of 1.15 bill gal for which compliance demonstrations would be made by February 28, 2011. As described in the NPRM, we believe that the deficit carryover provision provides a conceptual mechanism for this approach, since it would have allowed obligated parties to defer compliance with any or all of the 2009 standards until 2010. We are finalizing this approach in today's action. We believe it will ensure that these two year's worth of biomass-based diesel will be used, while providing reasonable lead time for obligated parties. It avoids a transition that fails to have any requirements related to the 2009 biomass-based diesel volume, and instead requires the use of the 2009 volume but achieves this by extending the compliance period by one year. We believe this is a reasonable exercise of our authority under section 211(o)(2) to issue regulations that ensure that the volumes for 2009 are ultimately used, even though we were unable to issue final regulations prior to the 2009 compliance year. We announced our intentions to implement the 2009 and 2010 biomass-based diesel requirements in this manner in the November 2008 Federal Register notice cited previously. We reiterated these intentions in our NPRM. Thus, obligated parties will have had sufficient lead time to acquire a sufficient number of biomass-based diesel RINs by the end of 2010 to comply with the standard based on 1.15 bill gal.

Data available at the time of this writing suggests that approximately 450 million gallons of biodiesel was produced in 2009, thus requiring 700 million gallons to be produced in 2010 to satisfy the combined 2009 and 2010 volume mandates. Information from commenters and other contacts in the biodiesel industry indicate that feedstocks and production facilities will be available in 2010 to produce this volume.

Refiners generally commented that the proposed approach to 2009 and 2010 biomass-based diesel volumes was not appropriate and should not be implemented. They also recommended that the RFS2 program should be made effective on January 1, 2011 with no carryover of any previous-year obligations for biomass-based diesel or any other volume mandate. In contrast, the National Biodiesel Board and several individual biodiesel producers supported the proposed approach, but believed it was insufficient to compel obligated parties to purchase biodiesel in 2009, something they considered critical to the survival of the biodiesel industry. Many of these commenters requested that we conduct an interim rulemaking that would apply to 2009 to implement the EISA mandated volume of 0.5 billion gallons of biomass-based diesel. If the RFS2 program could not be implemented until 2011, they likewise requested

[20] See 73 FR 70643 (November 21, 2008)

that interim measures be taken for 2010 to ensure that the full 1.15 bill gal requirement would be implemented. However, putting in place this new volume requirement without also putting in place EISA's new definition for biomass-based diesel, renewable fuel, and renewable biomass would have raised significant legal and policy issues that would necessarily have required a new proposal with its own public notice and comment process. Because of the significant time required for notice and comment rulemaking, the need to provide industry with adequate lead time for new requirements, and the fact that we were already well into calendar year 2009 at the time the request for an interim rule was received, it was unlikely that any interim rule could have impacted biodiesel demand in 2009. Moreover, Agency resources applied to the interim rulemaking would have been unavailable for development of the final RFS2 rulemaking. Developing an interim rule could have undermined EPA's ability to complete the full RFS2 program regulations in time for 2010 implementation. As a result, we did not pursue an interim rulemaking.

With regard to advanced biofuel, it is not necessary to implement a separate requirement for the 0.6 billion gallon mandate for 2009. Due to the nested nature of the volume requirements and the fact that Equivalence Values will be based on the energy content relative to ethanol, the 0.5 billion gallon requirement for biomass-based diesel will count as 0.75 billion gallons of advanced biofuel, exceeding the requirement of 0.6 billion gallons. Thus compliance with the biomass-based diesel requirement in 2009 automatically results in compliance with the advanced biofuel standard.

All 2009 biodiesel and renewable diesel RINs, identifiable through an RR code of 15 or 17 respectively under the RFS1 regulations, will be valid for showing compliance with the adjusted 2010 biomass-based diesel standard of 1.15 billion gallons. This use of previous year RINs for current year compliance is consistent with our approach to any other standard for any other year and consistent with the flexibility available to any obligated party that carries a deficit from one year to the next. Moreover, it allows an obligated party to acquire sufficient biodiesel and renewable diesel RINs during 2009 to comply with the 0.5 billion gallons requirement, even though their compliance demonstration would not occur until the 2010 compliance period.

We did not reduce the 2009 volume requirement for total renewable fuel by 0.5 billion gallons to account for the fact that we intended to move the compliance demonstration for this volume has been moved to the 2010 compliance period. Instead, we are allowing 2009 biodiesel and renewable diesel RINs to be used for compliance purposes for both the 2009 total renewable fuel standard as well as the 2010 adjusted biomass-based diesel standard (but not for the 2010 advanced biofuel or total renewable fuel standards). To accomplish this, we proposed in the NPRM that an obligated party would add up the 2009 biodiesel and renewable diesel RINs that he used for 2009 compliance with the RFS1 standard for total renewable fuel, and reduce his 2010 biomass-based diesel obligation by this amount. Thus, 2009 biodiesel and renewable diesel RINs are essentially used twice. Any remaining 2010 biomass-based diesel obligation would need to be covered either with 2009 biodiesel and renewable diesel RINs that were not used for compliance in 2009 or with 2010 biomass-based diesel RINs. We are finalizing this approach in today's notice.

b. Treatment of Deficit Carryovers, RIN Rollover, and RIN Valid Life For Adjusted 2010 Biomass-Based Diesel Requirement

Our transition approach for biomass-based diesel is conceptually similar, but not identical, to the statutory deficit carryover provision. In a typical deficit carryover situation, an obligated party can carry forward any amount of a current-year deficit to the following year. In the absence of any modifications to the deficit carryover provisions for our biomass-based diesel transition provisions, then, an obligated party that did not fully comply with the 2010 biomass-based diesel requirement of 1.15 billion gallons could carry a deficit of any amount into 2011. As described in the NPRM, we believe that the deficit carryover provisions should be modified in the context of the transition biomass-based diesel approach to more closely represent what would have occurred if we had been able to implement the 0.5 bill gal requirement in 2009. Specifically, we are prohibiting obligated parties from carrying over a biomass-based diesel deficit into 2011 larger than that based on the 0.65 bill gal volume requirement for 2010. This is the amount that would have been permitted had we been able to implement the biomass-based diesel requirements in 2009. In practice, this means that deficit carryovers from 2010 into 2011 for biomass-based diesel cannot not exceed 57% (0.65/1.15) of an obligated party's 2010 RVO. This approach also helps to ensure a minimum volume mandate for companies producing biomass-based diesel each year.

Similarly, in the absence of any modifications to the provisions regarding valid life of RINs, 2008 biodiesel and renewable diesel RINs could not be used for compliance in 2010 with the adjusted biomass-based diesel standard, despite the fact that the 2010 standard includes the 2009 requirement for which 2008 RINs should be valid. The National Biodiesel Board opposed this approach on the basis that the use of 2008 RINs for 2010 compliance demonstrations violated the 2-year valid life limit for RINs. However, since the 2010 compliance demonstration will include the obligation that would have applied in 2009, and 2008 RINs would be valid for 2009 compliance, we are allowing excess 2008 biodiesel and renewable diesel RINs that were not used for compliance purposes in 2008 to be used for compliance purposes in 2009 or 2010.

As described in Section III.D, we are requiring the 20% RIN rollover cap to apply in all years, and separately for all four standards. However, consistent with our approach to deficit carryovers, we believe that an additional constraint is warranted in the application of the rollover cap to the biomass-based diesel obligation in the 2010 compliance year to more closely represent what would have occurred if we had been able to implement the 0.5 bill gal requirement in 2009. Specifically, we are limiting the use of excess 2008 RINs to 20% of the statutory 2009 requirement of 0.5 bill gal. This is equivalent to 0.1 bill gal (20% of 0.5 bill gal), or 8.7% of the combined 2009/2010 obligation of 1.15 bill gal (0.1/1.15). Thus, obligated parties will be allowed to use excess 2008 and 2009 biodiesel and renewable diesel RINs for compliance with the 2010 combined standard of 1.15 bill gal, so long as the sum of all previous-year RINs (2008 plus 2009 RINs) does not exceed 20% of their 2010 obligation, and the 2008 RINs do not exceed 8.7% of their 2010 obligation.

Under RFS1, RINs are generated when renewable fuel is produced, but if the fuel is ultimately used for purposes other than as motor vehicle fuel the RINs must generally be retired. Under EISA, however, RINs generated for renewable fuel that is ultimately used for nonroad purposes, heating oil, or jet fuel are valid for compliance purposes. To more closely align our transition approach for biomass-based diesel to what could have occurred if we had issued the RFS2 standards prior to 2009, we are allowing 2009 RINs that are retired because they are ultimately used for nonroad, heating oil or jet fuel purposes to be valid for compliance with the 2010 standards. Such RINs can be reinstated by the retiring party in 2010.

3. Future Standards

The statutorily-prescribed phase-in period ends in 2012 for biomass-based diesel and in 2022 for cellulosic biofuel, advanced biofuel, and total renewable fuel. Beyond these years, EISA requires EPA to determine the applicable volumes based on a review of the implementation of the program up to that time, and an analysis of a wide variety of factors such as the impact of the production of renewable fuels on the environment, energy security, infrastructure, costs, and other factors. For these future standards, EPA must promulgate rules establishing the applicable volumes no later than 14 months before the first year for which such applicable volumes would apply. For biomass-based diesel, this would mean that final rules would need to be issued by October 31, 2011 for application starting on January 1, 2013. In today's rulemaking, we are not suggesting any specific volume requirements for biomass-based diesel for 2013 and beyond that would be appropriate under the statutory criteria that we must consider. Likewise, we are not suggesting any specific volume requirements for the other three renewable fuel categories for 2023 and beyond. However, the statute requires that the biomass-based diesel volume in 2013 and beyond must be no less than 1.0 billion gallons, and that advanced biofuels in 2023 and beyond must represent at a minimum the same percentage of total renewable fuel as it does in 2022. These provisions will be implemented as part of an annual standard-setting process.

F. Fuels that are Subject to the Standards

Under RFS1, producers and importers of gasoline are obligated parties subject to the standards - any party that produces or imports only diesel fuel is not subject to the standards. EISA changes this provision by expanding the RFS program in general to include all transportation fuel. As discussed above, however, section 211(o)(3) continues to require EPA to determine which refiners, blenders, and importers are treated as subject to the standard. As described further in Section II.G below, under this rule, the sum of all highway and nonroad gasoline and diesel fuel produced or imported within a calendar year will be the basis on which the RVOs are calculated. This section provides our final definition of gasoline and diesel for the purposes of the RFS2 program.

1. Gasoline

As with the RFS1 rule, the volume of gasoline used in calculating the RVO under RFS2 will continue to include all finished gasoline (reformulated gasoline (RFG) and conventional gasoline (CG)) produced or imported for use in the contiguous United States or Hawaii, as well as all unfinished gasoline that becomes finished gasoline upon the addition of oxygenate blended downstream from the refinery or importer. This includes both unfinished reformulated gasoline, called “reformulated gasoline blendstock for oxygenate blending,” or “RBOB,” and unfinished conventional gasoline designed for downstream oxygenate blending (e.g., sub-octane conventional gasoline), called "CBOB." The volume of any other unfinished gasoline or blendstock, (such as butane or naphtha produced in a refinery) or exported gasoline, will not be included in the obligated volume, except where the blendstock is combined with other blendstock or gasoline to produce finished gasoline, RBOB, or CBOB. Where a blendstock is blended with other blendstock to produce finished gasoline, RBOB, or CBOB, the total volume of the gasoline blend will be included in the volume used to determine the blender's renewable fuels obligation. Where a blendstock is added to finished gasoline, only the volume of the blendstock will be included, since the finished gasoline would have been included in the compliance determinations of the refiner or importer of the gasoline. For purposes of this preamble, the various gasoline products described above that we are including in a party's obligated volume are collectively called "gasoline."

Also consistent with the RFS1 program, we are continuing the exclusion of any volume of renewable fuel contained in gasoline from the volume of gasoline used to determine the renewable fuels obligations. This exclusion applies to any renewable fuels that are blended into gasoline at a refinery, contained in imported gasoline, or added at a downstream location. Thus, for example, any ethanol added to RBOB or CBOB at a refinery's rack or terminal downstream from the refinery or importer will be excluded from the volume of gasoline used by the refiner or importer to determine the obligation. This is consistent with how the standard itself is calculated – EPA determines the applicable percentage by comparing the overall projected volume of gasoline used to the overall renewable fuel volume that is specified in the statute, and EPA excludes ethanol and other renewable fuels that are blended into the gasoline in determining the overall projected volume of gasoline. When an obligated party determines their RVO by applying the applicable percentage to the amount of gasoline they produce or import, it is consistent to also exclude ethanol and other renewable fuel blends from the calculation of the volume of gasoline produced.

As with the RFS1 rule, Gasoline Treated as Blendstock (GTAB) will continue to be treated as a blendstock under the RFS2 program, and thus will not count towards a party's renewable fuel obligation. Where the GTAB is blended with other blendstock (other than renewable fuel) to produce gasoline, the total volume of the gasoline blend, including the GTAB, will be included in the volume of gasoline used to determine the renewable fuel obligation. Where GTAB is blended with renewable fuel to produce gasoline, only the GTAB volume will be included in the volume of gasoline used to determine the renewable fuel obligation. Where the GTAB is blended with finished gasoline, only the GTAB volume will be included in the volume of gasoline used to determine the renewable fuel obligation.

2. Diesel

EISA expanded the RFS program to include transportation fuels other than gasoline, thus both highway and nonroad diesel must be used in calculating a party's RVO. Any party that produces or imports petroleum-based diesel fuel that is designated as motor vehicle, nonroad, locomotive, and marine diesel fuel (MVNRLM) (or any subcategory of MVNRLM) will be required to include the volume of that diesel fuel in the determination of its RVO under the RFS2 rule. Diesel fuel includes any distillate fuel that meets the definition of MVNRLM diesel fuel as it has already been defined in the regulations at §80.2(qqq), including any subcategories such as MV (motor vehicle diesel fuel produced for use in highway diesel engines and vehicles), NRLM (diesel fuel produced for use in nonroad, locomotive, and marine diesel engines and equipment/vessels), NR (diesel fuel produced for use in nonroad engines and equipment), and LM (diesel fuel produced for use in locomotives and marine diesel engines and vessels)[21]. Transportation fuels meeting the definition of MVNRLM will be used to calculate the RVOs, and refiners, blenders, or importers of MVNRLM will be treated as obligated parties. As such, diesel fuel that is designated as heating oil, jet fuel, or any designation other than MVNRLM or a subcategory of MVNRLM, will not be subject to the applicable percentage standard and will not be used to calculate the RVOs.[22] We requested comment on the idea that any diesel fuel not meeting these requirements, such as distillate or residual fuel intended solely for use in ocean-going vessels, would not be used to calculate the RVOs.

One commenter expressed support for including heating oil and jet fuel into the RIN program, but not to subject these fuels to the RVO mandate. The commenter stated that fluctuating weather conditions make it hard to predict with any reliability the volumes of heating oil that will be used in a given year. Another commenter stated that it supports the extension of the RFS program to transportation fuels, including diesel and nonroad fuels.

With respect to fuels for use in ocean-going vessels, EISA specifies that "transportation fuels" do not include such fuels. We are interpreting that "fuels for use in ocean-going vessels" means residual or distillate fuels other than MVNRLM intended to be used to power large ocean-going vessels (e.g., those vessels that are powered by Category 3 (C3), and some Category 2 (C2), marine engines and that operate internationally). Thus, fuel for use in ocean-going vessels, or that an obligated party can verify as having been used in an ocean-going vessel, will be excluded from the renewable fuel standards. Also, in the context of the recently finalized fuel standards for C3 marine vessels, this would mean that fuel meeting the 1,000 ppm fuel sulfur standard would not be considered obligated volume, while all MVNRLM diesel fuel would.

3. Other Transportation Fuels

Transportation fuels other than gasoline or MVNRLM diesel fuel (natural gas, propane, and electricity) will not be used to calculate the RVOs of any obligated party. We believe this is a reasonable way to implement the obligations of 211(o)(3) because the volumes are small and the producers cannot readily differentiate the small portion used in the transportation sector from the large portion used in other sectors (in fact, the producer may have no knowledge of its ultimate use). We will reconsider this approach if and when these volumes grow. At the same time, it is clear that these fuels can be used as transportation fuel, and under certain circumstances, producers of such "other transportation fuels" may generate RINs as a producer or importer of a renewable fuel. See Section II.D.2.a for further discussion of other RIN-generating fuels.

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[21] EPA's diesel fuel regulations use the term "nonroad" to designate one large category of land based off-highway engines and vehicles, recognizing that locomotive and marine engines and vessels are also nonroad engines and vehicles under EPAct's definition of nonroad. Except where noted, the discussion of nonroad in reference to transportation fuel includes the entire category covered by EPAct's definition of nonroad.

[22] See 40 CFR 80.598(a) for the kinds of fuel types used by refiners or importers in designating their diesel fuel.

G. Renewable Volume Obligations (RVOs)

Under RFS1, each obligated party was required to determine its RVO based on the applicable percentage standard and its annual gasoline volume. The RVO represented the volume of renewable fuel that the obligated party was required to ensure was used in the U.S. in a given calendar year. Obligated parties were required to meet their RVO through the accumulation of RINs which represent the amount of renewable fuel used as motor vehicle fuel that was sold or introduced into commerce within the U.S. Each gallon-RIN counted as one gallon of renewable fuel for compliance purposes.

We are maintaining this approach to compliance under the RFS2 program. However, one primary difference between RFS1 and the new RFS2 program in terms of demonstrating compliance is that each obligated party now has four RVOs instead of one (through 2012) or two (starting in 2013) under the RFS1 program. Also, as discussed above, RVOs are now calculated based on production or importation of both gasoline and diesel fuels, rather than gasoline alone.

By acquiring RINs and applying them to their RVOs, obligated parties are deemed to have satisfied their obligation to cause the renewable fuel represented by the RINs to be consumed as transportation fuel in highway or nonroad vehicles or engines. Obligated parties are not required to physically blend the renewable fuel into gasoline or diesel fuel themselves. The accumulation of RINs will continue to be the means through which each obligated party shows compliance with its RVOs and thus with the renewable fuel standards.

If an obligated party acquires more RINs than it needs to meet its RVOs, then in general it can retain the excess RINs for use in complying with its RVOs in the following year (subject to the 20% rollover cap discussed in Section III.D) or transfer the excess RINs to another party. If, alternatively, an obligated party has not acquired sufficient RINs to meet its RVOs, then under certain conditions it can carry a deficit into the next year.

This section describes our approach to the calculation of RVOs under RFS2 and the RINs that are valid for demonstrating compliance with those RVOs. This includes a description of the special treatment that must be applied to RFS1 RINs used for compliance purposes under RFS2, since RINs generated under RFS1 regulations are not exactly the same as those generated in under RFS2.

1. Designation of Obligated Parties

In the NPRM, we proposed to continue to designate obligated parties under the RFS2 program as they were designated under RFS1, with the addition of diesel fuel producers and importers. Regarding gasoline producers and importers, we proposed that obligated parties who are subject to the standard would be those that produce or import finished gasoline (RFG and conventional) or unfinished gasoline that becomes finished gasoline upon the addition of an oxygenate blended downstream from the refinery or importer. Unfinished gasoline would include reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock designed for downstream oxygenate blending (CBOB) which is generally sub-octane conventional gasoline. The volume of any other unfinished gasoline or blendstock, such as butane, would not be included in the volume used to determine the RVO, except where the blendstock was combined with other blendstock or finished gasoline to produce finished gasoline, RBOB, or CBOB. Thus, parties downstream of a refinery or importer would only be obligated parties to the degree that they use non-renewable blendstocks to make finished gasoline, RBOB, CBOB, or diesel fuel.

We also took comment on two alternative approaches to the designation of obligated parties:

- Elimination of RBOB and CBOB from the list of fuels that are subject to the standard, such that a party's RVO would be based only on the non-renewable volume of finished gasoline or diesel that he produces or imports, thereby moving a portion of the obligation to downstream blenders of renewable fuels into RBOB and CBOB.

- Moving the obligations for all gasoline and diesel downstream of refineries and importers to parties who supply finished transportation fuels to retail outlets or to wholesale purchaser-consumer facilities.

These alternative approaches have the potential to more evenly align a party's access to RINs with that party's obligations under the RFS2 program. As described more fully in the NPRM, we considered these alternatives because of market conditions that had changed since the RFS1 program began. For instance, obligated parties who have excess RINs have been observed to retain rather than sell them to ensure they have a sufficient number for the next year's compliance. This was most likely to occur with major integrated refiners who operate gasoline marketing operations and thus have direct access to RINs for ethanol blended into their gasoline. Refiners whose operations are focused primarily on producing refined products with less marketing do not have such direct access to RINs and could potentially find it difficult to acquire a sufficient number for compliance despite the fact that the total nationwide volumes of renewable fuel meets or exceeds the standard. The result might be a higher price for RINs (and fuel) in the marketplace than would be expected under a more liquid RIN market. For similar reasons, we also took comment on possible changes to the requirement that RINs be transferred with volume through the distribution system as discussed more fully in Section II.H.4.

In response to the NPRM, stakeholders differed significantly on whether EPA should implement one of these alternative approaches. For instance, while some refiners expressed support for moving the obligations to downstream parties such as blenders, terminals, and/or wholesale purchaser-consumers, other refiners preferred to maintain the current approach. Blenders and other downstream parties generally expressed opposition to a change in the designation of obligated parties, citing the additional burden of demonstrating compliance with the standard especially for small businesses. They also pointed to the need to implement new systems for determining and reporting compliance, the short leadtime for doing so, and the fewer resources that smaller downstream companies have to manage such work in comparison to the much larger refiners. Finally, they pointed to the additional complexity that would be added to the RFS program beyond that which is necessary to carry out the renewable fuels mandate under CAA section 211(o).

When the RFS1 regulations were drafted, the obligations were placed on the relatively small number of refiners and importers rather than on the relatively large number of downstream blenders and terminals in order to minimize the number of regulated parties and keep the program simple. However, with the expanded RFS2 mandates, essentially all downstream blenders and terminals are now regulated parties under RFS2 since essentially all gasoline will be blended with ethanol. Thus the rationale in RFS1 for placing the obligation on just the upstream refiners and importers is no longer valid. Nevertheless, based on the comments we received, we do not believe that the concerns expressed warrant a change in the designation of obligated parties for the RFS2 program at this time. We continue to believe that the market will provide opportunities for parties who are in need of RINs to acquire them from parties who have excess. Refiners who market considerably less gasoline or diesel than they produce can establish contracts with splash blenders to purchase RINs. Such refiners can also purchase ethanol from producers directly, separate the RINs, and then sell the ethanol without RINs to blenders. Since the RFS program is based upon ownership of RINs rather than custody of volume, refiners need never take custody of the ethanol in order to separate RINs from volumes that they own. Moreover, a change in the designation of obligated parties would result in a significant change in the number of obligated parties and the movement of RINs, changes that could disrupt the operation of the RFS program during the transition from RFS1 to RFS2.

We will continue to evaluate the functionality of the RIN market. Should we determine that the RIN market is not operating as intended, driving up prices for obligated parties and fuel prices for consumers, we will consider revisiting this provision in future regulatory efforts.

In the NPRM we also took comment on several other possible ways to help ensure that obligated parties can demonstrate compliance. For instance, one alternative approach would have left our proposed definitions for obligated parties in place, but would have added a regulatory requirement that any party who blends ethanol into RBOB or CBOB must transfer the RINs associated with the ethanol to the original producer of the RBOB or CBOB. Stakeholders generally opposed this change, agreeing with our assessment that it would be extremely difficult to implement given that RBOB and CBOB are often transferred between multiple parties prior to ethanol blending. As a result, a regulatory requirement for RIN transfers back to the original producer would have necessitated an additional tracking requirement for RBOB and CBOB so that the blender would know the identity of the original producer. It would also be difficult to ensure that RINs representing the specific category of renewable fuel blended were transferred to the producer of the RBOB or CBOB, given the fungible nature of RINs assigned to batches of renewable fuel. For these reasons, we have not finalized this alternative approach.

Another alternative approach on which we took comment would have allowed use of RINs that expire without being used for compliance by an obligated party to be used to reduce the nationwide volume of renewable fuel required in the following year. This alternative approach could have helped to prevent the hoarding of RINs from driving up demand for renewable fuel. However, it would also effectively alter the valid life limit for RINs. Comments from stakeholders did not change our position that such an approach is not warranted at this time, and thus we have not finalized it.

2. Determination of RVOs Corresponding to the Four Standards

In order for an obligated party to demonstrate compliance, the percentage standards described in Section II.E.1 which are applicable to all obligated parties must be converted into the volumes of renewable fuel each obligated party is required to satisfy. These volumes of renewable fuel are the volumes for which the obligated party is responsible under the RFS program, and are referred to here as its RVO. Under RFS2, each obligated party will need to acquire sufficient RINs each year to meet each of the four RVOs corresponding to the four renewable fuel standards.

The calculation of the RVOs under RFS2 follows the same format as the formulas in the RFS1 regulations at §80.1107(a), with one modification. The standards for a particular compliance year must be multiplied by the sum of the gasoline and diesel volume produced or imported by an obligated party in that year rather than only the gasoline volume as under the RFS1 program[23]. To the degree that an obligated party did not demonstrate full compliance with its RVOs for the previous year, the shortfall will be included as a deficit carryover in the calculation. CAA section 211(o)(5) only permits a deficit carryover from one year to the next if the obligated party achieves full compliance with each of its RVOs including the deficit carryover in the second year. Thus deficit carryovers cannot occur two years in succession for any of the four individual standards. They can, however, occur as frequently as every other year for a given obligated party for each standard.

Note that a party that produces only diesel fuel will have an obligation for all four standards even though he will not have the opportunity to blend ethanol into his own gasoline. Likewise, a party that produces only gasoline will have an obligation for all four standards even though he will not have an opportunity to blend biomass-based diesel into his own diesel fuel.

3. RINs Eligible to Meet Each RVO

Under RFS1, all RINs had the same compliance value and thus it did not matter what the RR or D code was for a given RIN when using that RIN to meet the total renewable fuel standard. In contrast, under RFS2 only RINs with specified D codes can be used to meet each of the four standards.

As described in Section I.A.1, the volume requirements in EISA are generally nested within one another, so that any fuel that satisfies the advanced biofuel requirement also satisfies the total renewable fuel requirement, and fuel that meets either the cellulosic biofuel or the biomass-based diesel requirements also satisfies the advanced biofuel requirement. As a result, the RINs that can be used to meet the four standards are likewise nested. Using the D codes defined in Table II.A-1, the RFS2 RINs that can be used to meet each of the four standards are shown in Table II.G.3-1. RFS1 RINs generated in 2010 and identified by a D code of 1 or 2 can also be applied to these standards using the protocol described in Section II.G.4 below.

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[23] As discussed above, the diesel fuel that is used to calculate the RVO is any diesel designated as MVNRLM or a subcategory of MVNRLM.

Table II.G.3-1
RINs That Can Be Used To Meet Each Standard

Standard Obligation		Allowable D codes
Cellulosic biofuel	RVO_{CB}	3 and 7
Biomass-based diesel	RVO_{BBD}	4 and 7
Advanced biofuel	RVO_{AB}	3, 4, 5, and 7
Renewable fuel	RVO_{RF}	3, 4, 5, 6, and 7

The nested nature of the four standards also means that in some cases we must allow the same RIN to be used to meet more than one standard in the same year. Thus, for instance, a RIN with a D code of 3 can be used to meet three of the four standards, while a RIN with a D code of 5 can be used to meet both the advanced biofuel and total renewable fuel standards. However, a D code of 6 can only be used to meet the renewable fuel standard. Consistent with our proposal, we are continuing to prohibit the use of a single RIN for compliance purposes in more than one year or by more than one party[24].

4. Treatment of RFS1 RINs under RFS2

As described in the introduction to this section, we are implementing a number of changes to the RFS program as a result of the requirements in EISA. These changes will go into effect on July 1, 2010 and, among other things, will affect the conditions under which RINs are generated and their applicability to each of the four standards. As a result, RINs generated in 2010 under these RFS2 regulations will not be exactly the same as RINs generated under RFS1 regulations. Given the valid RIN life that allows a RIN to be used in the year generated or the year after, we must address circumstances in which excess 2009 RINs are used for compliance purposes in 2010. Also, since RINs generated in January through June of 2010 will be generated under RFS1 regulations, we must provide a means for them to be used to meet the annual 2010 RFS2 standards. Finally, we must address deficit carryovers from 2009 to 2010, since the total renewable fuel standards in these two years will be defined differently.

a. Use of RFS1 RINs to Meet Standards Under RFS2

In 2009 and the first three months of 2010, the RFS1 regulations will continue to apply and thus producers will not be required to demonstrate that their renewable fuel is made from renewable biomass as defined by EISA, nor that their combination of fuel type, feedstock, and process meets the GHG thresholds specified in EISA. Moreover, there is no practical way to determine after the fact if RINs generated under RFS1 regulations meet any of these criteria. However, we believe that the vast majority of RFS1 RINs generated in 2009 and the first two months of 2010 will in fact meet the RFS2 requirements. First, while ethanol made from corn must meet a 20% GHG threshold under RFS2 if produced by a facility that commenced construction after December 19, 2007, facilities that were already built or had commenced construction as of December 19, 2007 are exempt from this requirement. Essentially all ethanol

[24] Note that we are finalizing an exception to this general prohibition for the specific and limited case of 2008 and 2009 biodiesel and renewable diesel RINs used to demonstrate compliance with both the 2009 total renewable fuel standard and the 2010 biomass-based diesel standard. See Section II.E.2.a.

produced in 2009 and the first three months of 2010 will meet the prerequisites for this exemption. Second, it is unlikely that renewable fuels produced in 2009 or the first three months of 2010 will have been made from feedstocks that do not meet the new renewable biomass definition. It is very unlikely that new land would have been cleared or cultivated since December 19, 2007 for use in growing crops for renewable fuel production, and thus the land use restrictions associated with the renewable biomass definition will very likely be met. Finally, the text of section 211(o)(5) states that a "credit generated under this paragraph shall be valid to show compliance for the 12 months as of the date of generation," and EISA did not change this provision and did not specify any particular transition protocol to follow. A straightforward interpretation of this provision is to allow RFS1 RINs generated in 2009 and early 2010 to be valid to show compliance for the annual 2010 obligations.

The separate definitions for cellulosic biofuel and biomass-based diesel require GHG thresholds of 60% and 50%, respectively. While we do not have a mechanism in place to determine if these thresholds have been met for RFS1 RINs generated in 2009 or early 2010, any shortfall in GHG performance for this one transition period is unlikely to have a significant impact on long-term GHG benefits of the program. Few stakeholders commented on our proposed treatment of RFS1 RINs under RFS2. Of those that did, most supported our proposed approach to the use of RFS1 RINs to meet RFS2 obligations. Based on our belief that it is critical to the smooth operation of the program that excess 2009 RINs be allowed to be used for compliance purposes in 2010, we are allowing RFS1 RINs that were generated in 2009 or 2010 representing cellulosic biomass ethanol to be valid for use in satisfying the 2010 cellulosic biofuel standard. Likewise, we are allowing RFS1 RINs that were generated in 2009 or 2010 representing biodiesel and renewable diesel to be valid for use in satisfying the 2010 biomass-based diesel standard.

Consistent with our proposal, we have used information contained in the RR and D codes of RFS1 RINs to determine how those RINs should be treated under RFS2. The RR code is used to identify the Equivalence Value of each renewable fuel, and under RFS1 these Equivalence Values are unique to specific types of renewable fuel. For instance, biodiesel (mono alkyl ester) has an Equivalence Value of 1.5, and non-ester renewable diesel has an Equivalence Value of 1.7, and both of these fuels may be valid for meeting the biomass-based diesel standard under RFS2. Likewise, RINs generated for cellulosic biomass ethanol under RFS1 regulations must be identified with a D code of 1, and these fuels will be valid for meeting the cellulosic biofuel standard under RFS2. Our final treatment of RFS1 RINs for compliance under RFS2 is shown in Table II.G.4.a-1.

Table II.G.4.a-1
Treatment of RFS1 RINs for RFS2 Compliance Purposes

RINs Generated under RFS1[a]	Treatment under RFS2[b]
Any RIN with D code of 2 and RR code of 15 or 17	Equivalent to RFS2 RINs with D code of 4
All other RINs with D code of 2	Equivalent to RFS2 RINs with D code of 6
Any RIN with D code of 1	Equivalent to RFS2 RINs with D code of 3

[a] See RFS1 RIN code definitions at §80.1125
[b] See RFS2 RIN code definitions at §80.1425

b. Deficit Carryovers from the RFS1 Program to RFS2

The calculation of RVOs in 2010 under the RFS2 regulations will be somewhat different than the calculation of RVOs in 2009 under RFS1. In particular, 2009 RVOs were based on gasoline production only, while 2010 RVOs will be based on volumes of gasoline and diesel. As a result, 2010 compliance demonstrations that include a deficit carried over from 2009 will combine obligations calculated on two different bases.

We do not believe that deficits carried over from 2009 to 2010 will undermine the goals of the program in requiring specific volumes of renewable fuel to be used each year. Although RVOs in 2009 and 2010 will be calculated differently, obligated parties must acquire sufficient RINs in 2010 to cover any deficit carried over from 2009 in addition to that portion of their 2010 obligation which is based on their 2010 gasoline and diesel production. As a result, the 2009 nationwide volume requirement of 11.1 billion gallons of renewable fuel will be consumed over the two year period concluding at the end of 2010. Thus, we are not implementing any special treatment for deficits carried over from 2009 to 2010.

A deficit carried over from 2009 to 2010 will only affect a party's total renewable fuel obligation in 2010, as the 2009 obligation is for total renewable fuel use, not a subcategory. The RVOs for biomass-based diesel or advanced biofuel will not be affected, as they do not have parallel obligations in 2009 under RFS1[25].

H. Separation of RINs

As we proposed in the NPRM, we are requiring the RFS1 provisions regarding the separation of RINs from volumes of renewable fuel to be retained for RFS2. However, the modifications in EISA required changes to the treatment of RINs associated with nonroad renewable fuel and renewable fuels used in heating oil and jet fuel. Our approach to the separation of RINs by exporters must also be modified to account for the fact that there would be four categories of renewable fuel under RFS2.

1. Nonroad

[25] There is no cellulosic biofuel standard for 2010.

Under RFS1, RINs associated with renewable fuels used in nonroad vehicles and engines downstream of the renewable fuel producer were required to be retired by the party who owned the renewable fuel at the time of blending. This provision derived from the EPAct definition of renewable fuel which was limited to fuel used to replace fossil fuel used in a motor vehicle. However, EISA expands the definition of renewable fuel, and ties it to the definition of transportation fuel which is defined as any "fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels)." To implement these changes, the RFS2 program eliminates the RFS1 RIN retirement requirement for renewable fuels used in nonroad applications, with the exception of RINs associated with renewable fuels used in ocean-going vessels.

Since RINs have a valid life of two years, the NPRM proposed that a 2009 RFS1 RIN that is retired because the renewable fuel associated with it was used in nonroad vehicles or engines could be reinstated in 2010 for use in compliance with the 2010 standards. Stakeholders supported this approach, and we are finalizing it in today's action.

2. Heating Oil and Jet Fuel

EISA defines 'additional renewable fuel' as "fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in home heating oil or jet fuel."[26] While we are not requiring fossil-based heating oil and jet fuel to be included in the fuel used by a refiner or importer to calculate their RVOs, we are allowing renewable fuels used as or in heating oil and jet fuel to generate RINs. Similarly, RINs associated with a renewable fuel, such as biodiesel, that is blended into heating oil will continue to be valid for compliance purposes. See also discussion in Section II.B.1.e.

3. Exporters

Under RFS1, exporters were assigned an RVO representing the volume of renewable fuel that was exported, and they were required to separate all RINs that were assigned to fuel that was exported. Since there was only one standard, there was only one possible RVO applicable to exporters.

Under RFS2, there are four possible RVOs corresponding to the four categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel). However, given the fungible nature of the RIN system and the fact that an assigned RIN transferred with a volume of renewable fuel may not be the same RIN that was originally generated to represent that volume, RINs from different fuel types can accompany volumes. Thus, there may be no way for an exporter to determine from an assigned RIN which of the four categories applies to an exported volume. In order to determine its RVOs, the only information available to the exporter may be the type of renewable fuel that he is exporting.

However, if an exporter knows, or has reason to know, that the renewable fuel that it is exporting is either cellulosic biofuel or advanced biofuel, we are requiring the exporter to

[26] EISA, Title II, Subtitle A-Renewable Fuel Standard, Section 201.

determine an RVO for the exported fuel based upon these fuel types. For instance, if an exporter purchases cellulosic biofuel or advanced biofuel directly from a producer or if the fuel has been segregated from other fuels, we would expect the exporter to know or have reason to know the type of fuel that it is exporting. Another example of when we would expect an exporter to know or have reason to know that the fuel that it is exporting is cellulosic or advanced biofuel would be if the commercial documents that accompany the purchase or sale of the renewable fuel identify the product as cellulosic or advanced biofuel.

EPA recognizes that in many situations, exporters will not know or have reason to know which of the four categories of renewable fuel apply to the exported fuel. If this is the case, we are requiring exporters to follow the approach proposed in the NPRM. Exported volumes of biodiesel (mono alkyl esters) and renewable diesel must be used to determine the exporter's RVO for biomass-based diesel. For all other types of renewable fuel, the most likely category is general renewable fuel. Thus, we are requiring that all renewable fuels be used to determine the exporter's RVO for total renewable fuel. Our final approach is provided at §80.1430.

In the NPRM we took comment on an alternative approach in which the total nationwide volumes required in each year (see Table I.A.1-1) would be used to apportion specific types of renewable fuel into each of the four categories. For example, exported ethanol may have originally been produced from cellulose to meet the cellulosic biofuel requirement, from corn to meet the total renewable fuel requirement, or may have been imported as advanced biofuel. If ethanol were exported, we could divide the exported volume into three RVOs for cellulosic biofuel, advanced biofuel, and total renewable fuel using the same proportions represented by the national volume requirements for that year. However, as described in the NPRM, we believe that this alternative approach would have added considerable complexity to the compliance determinations for exporters without necessarily adding more precision. Given the expected small volumes of exported renewable fuel, we continue to believe that this added complexity is not warranted at this time.

As described above, exporters must separate any RINs assigned to renewable fuel that they export. However, since RINs are fungible and the owner of a batch of renewable fuel has the flexibility to assign between zero and 2.5 gallon-RINs to each gallon, we have made this flexibility explicit for exporters. Thus, an exporter can separate up to 2.5 gallon-RINs for each gallon of renewable fuel that he exports. While the exporter is not required to retain these separated RINs for use in complying with his RVOs calculated on the basis of the exported volumes, this would be the most straightforward approach and would ensure that the exporter has sufficient RINs to comply. However, we are aware of some exporters who sell RINs that they separate as a source of revenue, with the intention to purchase replacement RINs on the open RIN market later in the year to comply with their RVOs. At this time we are not aware of such activities resulting in noncompliance, and thus the RFS2 regulations promulgated today will continue to allow this. However, we may revisit this issue in the future if there is evidence that exporters are failing to comply because they are selling RINs that they separate from exported volumes.

4. Requirement to Transfer RINs with Volume

In the NPRM, we proposed that the approach to RIN transfers established under RFS1 - that RINs generated by renewable fuel producers and importers must be assigned to batches of renewable fuel and transferred along with those batches - be continued under RFS2. However, given the higher volumes required under RFS2 and the resulting expansion in the number of regulated parties, we also took comment on two alternative approaches to RIN transfers. Along with the alternative approaches for designation of obligated parties as described in Section II.G.1 above, a change to the requirement to transfer RINs with batches had the potential to more evenly align a party's access to RINs with that party's obligations under the RFS2 program. Nevertheless, for the reasons described below, we have determined that it would not be appropriate to implement these alternative approaches at this time.

In the first alternative approach, we would have removed the restriction established under the RFS1 rule requiring that RINs be assigned to batches of renewable fuel and transferred with those batches. Instead, renewable fuel producers could have sold RINs (with a K code of 2 rather than 1) separately from volumes of renewable fuel to any party.

In the second alternative approach, producers and importers of renewable fuels would be required to separate and transfer the RIN, but only to an obligated party. This "direct transfer" approach would require renewable fuel producers to transfer RINs with renewable fuel for all transactions with obligated parties, and sell all other RINs directly to obligated parties on a quarterly basis for any renewable fuel volumes that were not sold directly to obligated parties. Any RINs not sold in this way would be required to be offered for sale to any obligated party through a public auction. Only renewable fuel producers, importers, and obligated parties would be allowed to own RINs.

Many renewable fuel producers supported the concept of allowing them to separate the RINs from renewable fuel that they produce. They generally argued in favor of a free market approach to RINs in which there would be no restrictions on whom they could sell RINs to, or in what timeframe. The direct transfer approach was unnecessary, they argued, since the market would compel them to sell all RINs they generated, and all RINs would eventually end up in the hands of the obligated parties that need them. However, other renewable fuel producers opposed any change to the requirement that RINs be assigned to volumes of renewable and transferred with those volumes through the distribution system. They argued that the system established under RFS1 has proven to work and it would create an unwarranted burden to require producers to modify their IT systems for RFS2.

Marketers and distributors were generally opposed to our proposed alternative approaches to RIN transfers. Moreover, SIGMA and NACS, as in the RFS1 rulemaking process, recommended that RINs not be generated by producers at all, but rather by the party that blends renewable fuel into gasoline or diesel, or uses renewable fuel in its neat form as a transportation fuel.

Obligated parties generally opposed any change to the RFS1 requirement that RINs be assigned to volumes of renewable fuel by the producer or importer, and transferred with volumes through the distribution system. They reiterated their concern, first raised in the RFS1 rulemaking, that a free market approach would place them at greater risk of market manipulation by renewable fuel producers. Moreover, while generally expressing support for the concept of a direct transfer approach, they also expressed doubt that the auctions could be regulated in such a way as to ensure that RIN generators could not withhold RINs from the market by such means as failing to adequately advertise the time and location of an auction, by setting the selling price too high, by specifying a minimum number of bids before selling, by conducting auctions infrequently, by having unduly short bidding windows, etc. These concerns were exacerbated by the nested standards required by EISA, under which many obligated parties have expressed concern about being able to acquire sufficient RINs for compliance.

Given the significant challenges associated with a change to the requirement that RINs be transferred with volume and the opposing views among stakeholders, we are not making any change in today's final rule.

5. Neat Renewable Fuel and Renewable Fuel Blends Designated as Transportation Fuel, Heating Oil, or Jet Fuel

Under RFS1, RINs must, with limited exceptions, be separated by an obligated party taking ownership of the renewable fuel, or by a party that blends renewable fuel with gasoline or diesel. In addition, a party that designates neat renewable fuel as motor vehicle fuel may separate RINs associated with that fuel if the fuel is in fact used in that manner without further blending. One exception to these provisions is that biodiesel blends in which diesel constitutes less than 20 volume percent are ineligible for RIN separation by a blender. While EPA understands that in the vast majority of cases, biodiesel is blended with diesel in concentrations of 80 volume percent or less, there may be instances in which biodiesel is blended with diesel in concentrations of more than 80 percent biodiesel, but the blender is prohibited from separating RINs under the RFS1 regulations.

Thus, in order to account for situations in which biodiesel blends of 81 percent or greater may be used as transportation fuel, heating oil, or jet fuel without ever having been owned by an obligated party, EPA proposed, and is finalizing a change to the applicability of the RIN separation provisions for RFS2. Section 80.1429(b)(4) will allow for separation of RINs for neat renewable fuel or blends of renewable fuel and diesel fuel that the party designates as transportation fuel, heating oil, or jet fuel, provided the neat renewable fuel or blend is used in the designated form, without further blending, as transportation fuel, heating oil, or jet fuel. Those parties that blend renewable fuel with gasoline or diesel fuel (in a blend containing 80 percent or less biodiesel) must separate RINs pursuant to §80.1429(b)(2).

Thus, for example, if a party intends to separate RINs from a volume of B85, the party must designate the blend for use as transportation fuel, heating oil, or jet fuel and the blend must be used in its designated form without further blending. The party is also required to maintain records of this designation pursuant to §80.1454(b)(5). Finally, the party is required to comply with the proposed PTD requirements in §80.1453(a)(11)(iv), which serve to notify downstream parties that the volume of fuel has been designated for use as transportation fuel, heating oil, or jet fuel, and must be used in that designated form without further blending. Parties may separate RINs at the time they comply with the designation and PTD requirements, and do not need to physically track ultimate fuel use.

I. Treatment of Cellulosic Biofuel

1. Cellulosic Biofuel Standard

EISA requires that the Administrator set the cellulosic biofuel standard each November for the next year based on the lesser of the volume specified in the Act or the projected volume of cellulosic biofuel production based on EIA estimates for that year. In the event that the projected volume is less than the amount required in the Act, EPA may also reduce the applicable volume of the total renewable fuel and advanced biofuels requirement by the same or a lesser volume. We will examine EIA's projected volumes and other available data including the required production outlook reports discussed in Section II.K to decide the appropriate standard for the following year. The outlook reports from all renewable fuel producers will assist EPA in determining what the cellulosic biofuel standard should be and if the total renewable fuel and/or advanced biofuel standards should be adjusted. For years where EPA determines that the projected volume of cellulosic biofuels is not sufficient to meet the levels in EISA we will consider the availability of other advanced biofuels in deciding whether to lower the advanced biofuel standard as well.

In determining whether the advanced biofuel and/or total renewable fuel volume requirements should also be adjusted downward in the event that projected volumes of cellulosic biofuel fall short of the statutorily required volumes, we believe it may be appropriate to allow excess advanced biofuels to make up some or all of the shortfall in cellulosic biofuel. For instance, if we determined that sufficient biomass-based diesel was available, we could decide that the required volume of advanced biofuel need not be lowered, or that it should be lowered to a smaller degree than the required cellulosic biofuel volume. Thus, the Act requires EPA to examine the total and advanced renewable fuel standards and volumes in the event of a cellulosic volume waiver. EPA will look at projections for each year on an individual yearly basis to determine if the standards should be adjusted. EPA believes that since the standards are nested and the total and advanced renewable fuel volume mandates are met in part by the cellulosic volume mandate, Congress gave EPA the flexibility to lower the required total and advanced volumes, but Congress also wanted to encourage the development of advanced renewable fuels as well and allow in appropriate circumstances for the use of those fuels in the event they can meet that year's required volumes that would have been met by the cellulosic mandate.

2. EPA Cellulosic Biofuel Waiver Credits for Cellulosic Biofuel

Whenever EPA sets the cellulosic biofuel standard at a level lower than that required in EISA, but greater than zero, EPA is required to provide a number of cellulosic credits for sale that is no more than the volume used to set the standard. Congress also specified the price for such credits: adjusted for inflation, they must be offered at the price of the higher of 25 cents per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline in the United States. The inflation adjustment will be for years after 2008. The inflation adjustment will be based on the standard US inflation measure Consumer Price Index for All Urban Consumers (CPI-U) for All Items expenditure category as provided by the Bureau of Labor Statistics.[27]

Congress afforded the Agency considerable flexibility in implementing the system of cellulosic biofuel credits. EISA states EPA; "shall include such provisions, including limiting the credits' uses and useful life, as the Administrator deems appropriate to assist market liquidity and transparency, to provide appropriate certainty for regulated entities and renewable fuel producers, and to limit any potential misuse of cellulosic biofuel credits to reduce the use of other renewable fuels, and for such other purposes as the Administrator determines will help achieve the goals of this subsection."

We have fashioned a number of limitations on the use of cellulosic that reflect these considerations. Specifically, the credits will be called "Cellulosic Biofuel Waiver Credits" (or "waiver credits") so that there is no confusion with RINs or allowances used in the acid rain program. Such waiver credits will only be available for the current compliance year for which we have waived some portion of the cellulosic biofuel standard, they will only be available to obligated parties, and they will be nontransferable and nonrefundable. Further, obligated parties may only purchase waiver credits up to the level of their cellulosic biofuel RVO less the number of cellulosic biofuel RINs that they own. A company owning cellulosic biofuel RINs and cellulosic waiver credits may use both types of credits if desired to meet their RVOs, but unlike RINs obligated parties will not be able to carry waiver credits over to the next calendar year. Obligated parties may not use waiver credits to meet a prior year deficit obligation. These restrictions help ensure that waiver credits are not overutilized at the expense of actual renewable volume.

In the NPRM, EPA proposed that the credits could be usable for the advanced and total renewable standards similarly to cellulosic biofuel RINs. Several commenters stated this provision could displace advanced and total renewable fuel that was actually produced which would be against the intent of the Act, and that unlike RINs a company should only be permitted to use waiver credits to meet its cellulosic biofuel obligation. We agree, and are limiting the use of waiver credits for compliance with only a company's cellulosic biofuel RVO.

In the event the total volume of conventional gasoline and diesel fuel produced or imported in the country exceeds the projections used to set the standard, companies will still be able to purchase waiver credits up to their cellulosic volume obligation. When setting a reduced cellulosic biofuel standard EPA makes a determination that the cellulosic volume specified in EISA will not be met and that determination is not based on how much nonrenewable motor fuel will be produced. EPA sets the standard based on the volumes in the Act and a projection of gasoline production to ensure the obligation is broken up most equitably. EPA believes that Congress wanted all obligated parties to have equal access to the waiver credits in the event of the waiver and did not want obligated parties to incur a deficit due to the timing of when they purchased waiver credits.

[27] See U.S. Department of Labor, Bureau of Labor Statistics (BLS), Consumer Price Index website at: http://www.bls.gov/cpi/.

Cellulosic Biofuel Waiver Credits, in the event of a waiver, will be offered in a generic format rather than a serialized format, like RINs. Waiver credits can be purchased using procedures defined by the EPA, and at the time that an obligated party submits its annual compliance demonstration to the EPA and establishes that it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. EPA will define these procedures with the US Treasury before the end of the first annual compliance period. EPA will publish these procedures with the obligated party annual compliance report template. EPA will provide the forms necessary to purchase the credits. EPA intends to provide options for obligated parties to use Pay.Gov or if desired to mail payment to the US Treasury.

The wholesale price of gasoline used by EPA in setting the price of the waiver credits will be based on the average monthly bulk (refinery gate) price of gasoline using data from the most recent twelve months of data from EIA available to EPA at the time it develops the cellulosic biofuel standard. [28] EPA will use refinery gate price, U.S. Total Gasoline Bulk Sales (Price) by Refiners from EIA in calculating the average, since it is the price most reflective of what most obligated parties are selling their fuel. EPA will use the most recent twelve months of data provided by EIA to develop an average price on actual volumes produced in the year prior to the compliance year. In order to provide regulatory certainty, we will set the waiver credits price for the following year each November when and if we set a cellulosic biofuel standard for the following year that is based on achieving a lower volume of cellulosic biofuel use than is specified in EISA.

For the 2010 compliance period, since the cellulosic standard is lower than the level otherwise required by EISA, we are also making cellulosic waiver credits available to obligated parties for end-of-year compliance should they need them at a price of $1.56 per gallon-RIN. The price for the 2011 compliance period, if necessary will be set when we announce the 2011 cellulosic biofuel standard.

3. Application of Cellulosic Biofuel Waiver Credits

While the credit provisions of section 202(e) of EISA ensure that there is a predictable upper limit to the price that cellulosic biofuel producers can charge for a gallon of cellulosic biofuel and its assigned RIN, there may be circumstances in which this provision has other unintended consequences. This could occur in situations where the cost of total renewable fuel RINs exceeds the cost of the cellulosic waiver credits. To prevent this, we sought comment on and are finalizing an additional restriction: an obligated party may only purchase waiver credits from the EPA to the degree that it establishes it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. This approach forces obligated parties to apply all their cellulosic biofuel RINs to their cellulosic biofuel RVO before applying any waiver credits to their cellulosic biofuel RVO.

Even with this restriction the approach in the NPRM might not have operated as intended. For instance, if the combination of cellulosic biofuel volume price and RIN price were

[28] More information on wholesale gasoline prices can be found on the Department of Energy's (DOE), Energy Information Administration's (EIA) website at:
http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=A103B00002&f=M

to become low compared to that for general renewable fuel, a small number of obligated parties could have purchased more cellulosic biofuel than they need to meet their cellulosic biofuel RVOs and could have used the additional cellulosic biofuel RINs to meet their advanced biofuel and total renewable fuel RVOs. Other obligated parties would then have had no access to cellulosic biofuel volume nor cellulosic biofuel RINs, and would have been forced to purchase waiver credits from the EPA. This situation would have had the net effect of waiver credits replacing advanced biofuels and/or general renewable fuel rather than cellulosic biofuel. Based on comments received on the NPRM, EPA is placing the additional restriction of only allowing the waiver credits to count towards the cellulosic biofuel standard and not the advanced or renewable fuel standards.

Moreover, under certain conditions it may be possible for the market price of general renewable fuel RINs to be significantly higher than the market price of cellulosic biofuel RINs, as the latter is limited in the market by the price of EPA-generated waiver credits according to the statutory formula described in Section II.I.2 above. Under some conditions, this could result in a competitive disadvantage for cellulosic biofuel in comparison to corn ethanol, for example. For instance, if gasoline prices at the pump are significantly higher than ethanol production costs, while at the same time corn-ethanol production costs are lower than cellulosic ethanol production costs, profit margins for corn-ethanol producers will be larger than for cellulosic ethanol producers. Under these conditions, while obligated parties may still purchase cellulosic ethanol volume and its associated RINs rather than waiver credits, cellulosic ethanol producers will realize lower profits than corn-ethanol producers due to the upper limit placed on the price of cellulosic biofuel RINs through the pricing formula for waiver credits. For a newly forming and growing cellulosic biofuel industry, this competitive disadvantage could make it more difficult for investors to secure funding for new projects, threatening the ability of the industry to reach the statutorily mandated volumes.

Finally, in the NPRM we sought comment on a "dual RIN" approach to cellulosic biofuel. In this approach, both cellulosic biofuel RINs (with a D code of 3) and waiver credits would have only been applied to an obligated party's cellulosic biofuel RVO, but producers of cellulosic biofuel would also generate an additional RIN representing advanced biofuel (with a D code of 5). The producer would have only been required to transfer the advanced biofuel RIN with a batch of cellulosic biofuel, and could retain the cellulosic biofuel RIN for separate sale to any party[29]. The cellulosic biofuel and its attached advanced biofuel RIN would then have competed directly with other advanced biofuel and its attached advanced biofuel RIN, while the separate cellulosic biofuel RIN would have an independent market value that would have been effectively limited by the pricing formula for waiver credits as described in Section II.I.2. However, this approach would have been a more significant deviation from the RIN generation and transfer program structure that was developed cooperatively with stakeholders during RFS1. It would have provided cellulosic biofuel producers with significantly more control over the sale and price of cellulosic biofuel RINs, which was one of the primary concerns of obligated parties during the development of RFS1. Therefore, EPA is treating the transfer of cellulosic RINs in the same manner as the other required volumes.

[29] The cellulosic biofuel RIN would be a separated RIN with a K code of 2 immediately upon generation.

J. Changes to Recordkeeping and Reporting Requirements

1. Recordkeeping

Recordkeeping, including product transfer documents (PTDs), will support the enforcement of the use of RINs for compliance purposes. Parties are afforded significant freedom with regard to the form that PTDs take. Product codes may be used as long as they are understood by all parties, but they may not be used for transfers to truck carriers or to retailers or wholesale purchaser-consumers. Parties must keep copies of all PTDs they generate and receive, as well as copies of all reports submitted to EPA and all records related to the sale, purchase, brokering or transfer or RINs, for five (5) years. Parties must keep copies of records that relate to program flexibilities, such as small business-oriented provisions. Upon request, parties are responsible for providing their records to the Administrator or the Administrator's authorized representative. We reserve the right to request to receive documents in a format that we can read and use.

In Section III.A. of this preamble, we describe an EPA-Moderated Transaction System (EMTS) for RINs. The new system allows for “real-time” recording of transactions involving RINs.

2. Reporting

Producers and importers who generate or take ownership of RINs shall submit RIN Transaction Reports[30] and/or RIN Generation Reports quarterly. Renewable fuel exporters and obligated parties shall submit their RIN Transaction Reports quarterly, and RIN owners shall submit their RIN Transaction Reports quarterly. EMTS will be used by all parties to record “real time” generation of RINs and transactions involving RINs starting July 1, 2010. "Real time” means recordation within five (5) business days of generation or any transaction involving a RIN.

Quarterly reports are to be submitted on the following schedule. Quarterly reports include RIN Activity Reports and, with EMTS, simplified reporting and certification of the RIN Generation and RIN Transaction Reports.

Table II.J-1
Quarterly Reporting Schedule

Quarter Covered by Report	Due Date for Report
January - March	May 31
April - June	August 31
July - September	November 30
October - December	February 28

[30] For ease of reference, the current RFS (i.e. RFS1) form may be viewed at the EPA Fuels Reporting website at the following URL: http://www.epa.gov/otaq/regs/fuels/rfsforms.htm (accessed November 16, 2009). These forms will be updated for RFS2.

Annual reports (covering January through December) would continue to be due on February 28. The only annual report is the Obligated Party Annual Compliance Report.[31]

Simplified, secure reporting is currently available through our Central Data Exchange (CDX). CDX permits us to accept reports that are electronically signed and certified by the submitter in a secure and robustly encrypted fashion. Using CDX eliminates the need for wet ink signatures and reduces the reporting burden on regulated parties. EMTS will also make use of the CDX environment.

Due to the criteria that renewable fuel producers and importers must meet in order to generate RINs under RFS2, and due to the fact that renewable fuel producers and importers must have documentation about whether their feedstock(s) meets the definition of "renewable biomass," we proposed several changes to the RIN Generation Report.[32] We proposed to make the report a more general report on renewable fuel production in order to capture information on all batches of renewable fuel, whether or not RINs are generated for them. This final rule adopts the proposed approach. All renewable fuel producers and importers above 10,000 gallons per year must report to EPA on each batch of their fuel and indicate whether or not RINs are generated for the batch. If RINs are generated, the producer or importer is required to certify that his feedstock meets the definition of "renewable biomass." If RINs are not generated, the producer or importer must state the reason for not generating RINs, such as they have documentation that states that their feedstock did not meet the definition of "renewable biomass," or the fuel pathway used to produce the fuel was such that the fuel did not qualify to generate RINs as a renewable fuel. For each batch of renewable fuel produced, we require information about the types and volumes of feedstock used and the types and volumes of co-products produced, as well as information about the process or processes used. This information is necessary to confirm that the producer or importer assigned the appropriate D code to their fuel and that the D code was consistent with their registration information. In this final rule, we adopt the approach set forth in the notice of proposed rulemaking.

In addition, we proposed two changes for the RIN Transaction Report[33]. First, for reports of RINs assigned to a volume of renewable fuel, the volume of renewable fuel must be reported. Second, RIN price information must be submitted for transactions involving both separated RINs and RINs assigned to a renewable volume. This information was not collected under RFS1, but because we believe this information has great programmatic value to EPA, we proposed to collect it for RFS2. As we explained in the proposed rule, price information may help us to anticipate and appropriately react to market disruptions and other compliance challenges, will be beneficial when setting future renewable standards, and will provide additional insight into the market when assessing potential waivers. Our incomplete knowledge regarding RIN pricing for RFS1 adversely affected our ability to assess the general health and direction of the market and overall liquidity of RINs. Because we believe the inclusion of price information in reports will be beneficial to both EPA and to regulated parties, this final rule includes that information element in reports, as well as incorporating it as part of the "real time" transactional information collected via EMTS.

[31] For RFS1, this form is numbered RFS0300.
[32] For RFS1, this form is numbered RFS0400.
[33] For RFS1, this form is numbered RFS0200.

3. Additional Requirements for Producers of Renewable Natural Gas, Electricity, and Propane

In addition to the general reporting requirement listed above, we are requiring an additional item of reporting for producers of renewable natural gas, electricity, and propane who choose to generate and assign RINs. While producers of renewable natural gas, electricity, and propane who generate and assign RINs are responsible for filing the same reports as other producers of RIN-generating renewable fuels, we are requiring that additional reporting for these producers support the actual use of their products in the transportation sector. We believe that one simple way to achieve this may be to add a requirement that producers of renewable natural gas, electricity, and propane add the name of the purchaser (e.g., the name of the wholesale purchaser-consumer (WPC) or fleet) to their RIN generation reports and then maintain appropriate records that further identify the purchaser and the details of the transaction. We are not requiring that a purchaser who is either a WPC or an end user would have to register under this scenario, unless that party engages in other activities requiring registration under this program.

4. Attest Engagements

The purpose of an attest engagement is to receive third party verification of information reported to EPA. An attest engagement, which is similar to a financial audit, is conducted by a Certified Public Accountant (CPA) or Certified Independent Auditor (CIA) following agreed-upon procedures. We have found the information in attest engagements submitted under RFS1 to be extremely valuable as a compliance monitoring tool. The approach adopted in this final rule is identical to the approach adopted under the RFS1 program,[34] although the universe of obligated parties and renewable fuels producers is broader under this final rule for RFS2.

As with the RFS1 program, an attest engagement must be conducted by an individual who is a Certified Public Accountant (CPA) or Certified Internal Auditor (CIA), who is independent of the party whose records are being reviewed, and who will follow agreed-upon procedures to determine whether underlying records, reported items, and transactions agree. The CPA or CIA will generate a report as to their findings.

We have received numerous question and comments related to how attest engagements apply to foreign companies and whether or not a foreign accountant may perform the required agreed-upon procedures. EPA will accept an attest engagement performed by a foreign accountant who holds an equivalent credential to an American CPA or CIA. A written explanation as to the foreign accountant's qualifications and the equivalency of the credential must accompany the attest engagement.

Producers of renewable fuels, obligated parties, exporters, and any party who owns RINs must arrange for an annual attest engagement. The attest engagement report for any given year

[34] See "Regulation of Fuel and Fuel Additives: Renewable Fuel Standard Program," 72 FR 23900, 23949-23950 (May 1, 2007) for a detailed discussion of attest engagement requirements under RFS1.

must be submitted to EPA by no later than May 31 of the following year. Section 80.1464 of the regulations specifies the attest engagement procedures to be followed.

K. Production Outlook Reports

Under this program we are requiring the submission, starting in 2010, of annual production outlook reports from all domestic renewable fuel producers, foreign renewable fuel producers who register to generate RINs, and importers of renewable fuels. These production outlook reports will be similar in nature to the pre-compliance reports required under the Highway and Nonroad Diesel programs. These reports will contain information about existing and planned production capacity, long-range plans, and feedstocks and production processes to be used at each production facility. For expanded production capacity that is planned or underway at each existing facility, or new production facilities that are planned or underway, the progress reports will require information on: 1) Strategic planning; 2) Planning and front-end engineering; 3) Detailed engineering and permitting; 4) Procurement and construction; 5) Commissioning and startup; 6) Projected volumes; 7) Contracts currently in place (feedstocks, sales, delivery, etc.); and 8) Whether or not feedstocks have been purchased. The first five project phases are described in EPA's June 2002 Highway Diesel Progress Review report (EPA document number EPA420-R-02-016, located at: www.epa.gov/otaq/regs/hd2007/420r02016.pdf). In the proposed rule, we asked for comment on the first five project phases, and whether or not they were appropriate for renewable fuels production. We also proposed additional phases in order to provide better specificity for ascertaining industry status. EPA plans to use this information in order to provide annual summary reports regarding such planned capacity.

The full list of requirements for the production outlook reports is provided in the regulations at §80.1449. The information submitted in the reports will be used to evaluate the progress that the industry is making towards the renewable fuels volume goals mandated by EISA. They will help EPA set the annual cellulosic biofuel standard and consider whether waivers would be appropriate with respect to the advanced biofuel, biomass-based diesel, and total renewable fuel standards (see Section II.I of this preamble for more discussion on this). Production outlook reports will be due annually by March 31 (except that for the year 2010, the report will be due September 1) and each annual report must provide projected information, including any updated information from the previous year's report.

As mentioned in the preamble to the proposed rule, EPA currently receives data on projected flexible-fuel vehicle (FFV) sales and conversions from vehicle manufacturers. These are helpful in providing EPA with information regarding the potential market for renewable fuels. We requested comment on whether we should require the annual submission of data to facilitate our evaluation of the ability of the distribution system to deliver the projected volumes of biofuels to petroleum terminals that are needed to meet the RFS2 standards, the extent to which such information is already publicly available or can be purchased from a proprietary source, and the extent to which such publicly available or purchasable data would be sufficient for EPA to make its determination. We further requested comment on the parties that should be required to report to EPA, and data requirements. We believe that publicly available information on E15, E85, and other refueling facilities is sufficient for us to make a determination about the adequacy of such facilities to support the projected volumes that would be used to satisfy the RFS2 standards. Therefore, we are not finalizing such a requirement.

While we understand that the types of projections we request in the Outlook Reports could be somewhat speculative in nature, we believe that the projections will provide us with the most reliable information possible to inform the annual RFS standards and waiver considerations. Further, we believe this information will be more useful to us than other public information that is released in other contexts (e.g., announcements for marketing purposes). As mentioned above in Section II.I, we believe that we can use this information to supplement other available information (such as volume projections from EIA) to help set the standard for the following year. Specifically, it will provide more accurate information for setting the cellulosic biofuel and biomass-based diesel standards, and any adjustments to the advanced biofuel and total renewable fuel standards.

We received comments that both support and oppose the Production Outlook Reports, or some element of them. One commenter stated that EPA provided no reasonable explanation to require the information being requested for the reports; the commenter further stated that such information is not needed to assist parties to come into compliance. Another commenter stated that the renewable fuels industry cannot confidently project what will happen in 2010, or even 2020, because there are too many unknowns, no previous history of renewable fuels mandates, and no sense of continued tax rebate. The commenter suggested that until the industry operates for a few years under the RFS2 carve-outs and the issues on the tax rebates for renewables are resolved, the industry cannot develop a meaningful outlook forecast. The commenter further suggested that EPA instead hire a consultant who can look at the big picture and provide a more meaningful evaluation than could the individual members of the biofuels industry. However, as discussed above, while these reports will have their limitations, we believe they will provide the best and most up to date information available for us to use in setting the standards and considering any waiver requests. We will of course also look to other publicly available information, and may consider using contractors to help out in this regard, but it cannot replace the need for the production outlook report data.

A commenter noted that this provision is similar to reports required under the diesel program. The commenter further stated that if the required information can be captured by EMTS, the commenter fully supports this requirement. However, the commenter stated that it is opposed to some of the required elements of the reports for planned expanded or new production (strategic planning, planning and front-end engineering, detailed engineering and permitting, procurement and construction, and commissioning and start-up); these are an aspect of financial planning that the commenter believes EPA has no jurisdiction over and cannot derive basis from EISA in any form regardless of interpretation. As explained above, this information will be used by EPA to inform us for setting the standards on an annual basis and in responding to any waiver petitions. It will not be used to assess compliance with the program. The other provisions for registration, recordkeeping and reporting serve that purpose.

Another commenter stated that the reports should be required, but that EPA should not rely too heavily upon the data (particularly for new biofuel technologies). Some commenters noted that they believe that requiring Production Outlook Reports is duplicative in nature and/or a burden to the industry. These commenters also believe that EPA already receives such information through the reporting that currently exists, and that EPA could also obtain this information from DOE's Energy Information Administration (EIA) and the National Biodiesel Board (NBB). Other commenters expressed concern over reporting such confidential and strategic information (even as confidential business information (CBI)), and that information out to 2022 seems excessive and useless; and that the reports should be limited to just domestic and foreign producers of renewable fuels but not importers (as they tend to import renewable fuels based on variable economic conditions and will not likely have the ability to reliably predict their future import volumes). The information that currently exists from other sources is current and historical information. For the purposes of setting future standards, we need to have information on future plans and projections. We understand that reality will always be different from the projections, but they will still give us the best possible source of information. Furthermore, by having projections five years out into the future, and then obtaining new reports every year, we will be able to assess the trends in the data and reports to better utilize them over time.

Some commenters have expressed concern that the information required for Production Outlook Reports is not needed, won't provide useful information because it is speculative, or asks for information that could be sensitive/confidential. However, we continue to believe that such information is essential to our annual cellulosic biofuel standard setting, and consideration of whether waivers should be provided for other standards. All information submitted to EPA will be treated as confidential business information (CBI), and if used by EPA in a regulatory context will only be reported out in very general terms. As with our Diesel Pre-compliance Reports, we fully expect that the information will be somewhat speculative in the early reports, and we will weight it accordingly. As the program progresses, however, information submitted for the reports will continue to improve. We believe that any information, whether speculative or concrete, will be helpful for the purposes described above. Thus we are finalizing Production Outlook Reports, and the required elements at §80.1449.

L. What Acts Are Prohibited and Who Is Liable for Violations?

The prohibition and liability provisions under this rule are similar to those of the RFS1 program and other fuels programs in 40 CFR Part 80. The rule identifies certain prohibited acts, such as a failure to acquire sufficient RINs to meet a party's RVOs, producing or importing a renewable fuel that is not assigned a proper RIN category (or D Code), improperly assigning RINs to renewable fuel that was not produced with renewable biomass, failing to assign RINs to qualifying fuel, or creating or transferring invalid RINs. Any person subject to a prohibition is liable for violating that prohibition. Thus, for example, an obligated party is liable if the party failed to acquire sufficient RINs to meet its RVO. A party who produces or imports renewable fuels is liable for a failure to assign proper RINs to qualifying batches of renewable fuel produced or imported. Any party, including an obligated party, is liable for transferring a RIN that was not properly identified.

In addition, any person who is subject to an affirmative requirement under this program is liable for a failure to comply with the requirement. For example, an obligated party is liable for a failure to comply with the annual compliance reporting requirements. A renewable fuel producer or importer is liable for a failure to comply with the applicable batch reporting requirements. Any party subject to recordkeeping or product transfer document (PTD) requirements is liable for a failure to comply with these requirements. Like other EPA fuels programs, this rule provides that a party who causes another party to violate a prohibition or fail to comply with a requirement may also be found liable for the violation.

EPAct amended the penalty and injunction provisions in section 211(d) of the Clean Air Act to apply to violations of the renewable fuels requirements in section 211(o). Accordingly, any person who violates any prohibition or requirement of this rule is subject to civil penalties of up to $37,500 per day and per each individual violation, plus the amount of any economic benefit or savings resulting from each violation. Under this rule, a failure to acquire sufficient RINs to meet a party's renewable fuels obligation constitutes a separate day of violation for each day the violation occurred during the annual averaging period.

As discussed above, the regulations prohibit any party from creating or transferring invalid RINs. These invalid RIN provisions apply regardless of the good faith belief of a party that the RINs are valid. These enforcement provisions are necessary to ensure the RFS2 program goals are not compromised by illegal conduct in the creation and transfer of RINs.

As in other motor vehicle fuel credit programs, the regulations address the consequences if an obligated party is found to have used invalid RINs to demonstrate compliance with its RVO. In this situation, the obligated party that used the invalid RINs will be required to deduct any invalid RINs from its compliance calculations. An obligated party is liable for violating the standard if the remaining number of valid RINs was insufficient to meet its RVO, and the obligated party might be subject to monetary penalties if it used invalid RINs in its compliance demonstration. In determining what penalty is appropriate, if any, we would consider a number of factors, including whether the obligated party did in fact procure sufficient valid RINs to cover the deficit created by the invalid RINs, and whether the purchaser was indeed a good faith purchaser based on an investigation of the RIN transfer. A penalty might include both the economic benefit of using invalid RINs and/or a gravity component.

Although an obligated party is liable under our proposed program for a violation if it used invalid RINs for compliance purposes, we would normally look first to the generator or seller of the invalid RINs both for payment of penalty and to procure sufficient valid RINs to offset the invalid RINs. However, if, for example, that party was out of business, then attention would turn to the obligated party who would have to obtain sufficient valid RINs to offset the invalid RINs.

III. Other Program Changes

In addition to the regulatory changes we are finalizing today in response to comments received on the proposed rule and EISA (which are designed to implement the provisions of RFS2), there are a number of other changes to the RFS program that we are making. We believe that these changes will increase flexibility, simplify compliance, or address RIN transfer issues that have arisen since the start of the RFS1 program. Throughout the rulemaking process, we also investigated impacts on small businesses and we are finalizing provisions to address the impacts of the program on them.

A. The EPA Moderated Transaction System (EMTS)

The EPA Moderated Transaction System (EMTS) emerged as a result of our experiences with and lessons learned from implementing RFS1. Recognizing that the addition of significant volumes of renewable fuels and expansion of renewable fuel categories were adding complexity to an already stressed system, EMTS was introduced as a new approach for managing RINs in our NPRM. We received broad acceptance of the EMTS concept in the public comments as well as support for its expeditious implementation. This section describes the need for EMTS, implementation of EMTS, and an explanation of how EMTS will work. By implementing EMTS, we believe that we will be able to greatly reduce RIN-related errors while efficiently and accurately managing the universe of RINs. EMTS will save considerable time and resources for both industry and EPA. This is most evident considering that the system virtually eliminates multiple sources of administrative errors, resulting in a reduction of costs and effort expended to correct and regenerate product transfer documents, documentation and recordkeeping, and resubmitting reports to EPA. Use of EMTS will result in fewer report resubmissions and easier reporting for industry, while leaving fewer reports to be processed by EPA. Industry will spend less time and effort validating the RINs they procure with greater assurance and confidence in the RIN market. EPA will spend less time tracking down invalid RINs and working with regulated parties on complex remedial actions. This is possible because EMTS removes management of the 38-digit RIN from the hands of the reporting community. At the same time, EPA and the reporting community will be working with a standardized system, reducing stresses and development costs on IT systems.

We received comments suggesting that EPA remove the attest engagement requirements and certain recordkeeping requirements due to the use of EMTS. While we believe that EMTS will simplify and reduce burdens on the regulated community, it is important to point out that EMTS is strictly a RIN tracking and managing tool designed to facilitate reporting under the Renewable Fuel Standard program. Product transfer documents are the commercial documents used to memorialize transactions of RINs between a buyer and a seller in the market. The EMTS will rely on references to these documents, which can take many forms, but it is not capable of replacing those documents. Attest engagements are used to verify that the records required to be kept by regulated parties, including information retained by a regulated party as well as information reported to EPA such as laboratory test results, contracts between renewable fuel/RIN buyers and sellers, feedstock documentation, etc. is correctly maintained or reported. The information reported via EMTS is but a subset of the information required to be maintained in a regulated party's records, and both PTDs and attest engagements are necessary to ensure that the information collected and tracked in EMTS concurs with actual events.

1. Need for the EPA Moderated Transaction System

In implementing RFS1, we found that the 38-digit standardized RINs proved to be confusing to many parties in the distribution chain. Parties made various errors in generating and using RINs. For example, parties transposed digits within the RIN and incorrectly referenced volume numbering. Also, parties created alphanumeric RINs, despite the fact that RINs were supposed to consist of all numbers.

Once an error is made within a RIN, the error propagates throughout the distribution system. Correcting an error can require significant time and resources and usually involves many steps. Not only must reports to EPA be corrected, underlying records and reports reflecting RIN transactions must also be located and corrected to reflect discovery of an error. Because reporting related to RIN transactions under RFS1 was only on a quarterly basis, a RIN error could exist for several months before being discovered.

Incorrect RINs are invalid RINs. If parties in the distribution system cannot track down and correct errors in a timely manner, then all downstream parties that traded the invalid RIN are in violation. Because RINs are the basic unit of compliance for the RFS program, it is important that parties have confidence when generating and using them.

All parties in the RFS1 and the RFS2 regulated community are required to use RINs. Under RFS2, we foresee that regulated party community will substantially expand. Newer regulated parties of an already complex system necessitate EMTS. These parties include renewable fuel producers and importers, obligated parties, exporters, and other RIN owners; (typically marketers of renewable fuels and blenders). Under RFS1, all RINs were used to comply with a single standard. With RFS2, there are four standards. RINs must be generated to identify one of the fuel categories: cellulosic biofuel, cellulosic diesel, biomass-based diesel, advanced biofuel, and renewable fuels (e.g., corn ethanol). (For a more detailed discussion of RINs, see Section II.A of this preamble.) The different types of RINs will be managed in the EMTS.

2. Implementation of the EPA Moderated Transaction System

We proposed that EMTS would be an opt-in for the calendar year 2010 and mandatory for calendar year 2011. We received many comments strongly supporting EMTS implementation with the start of the RFS2 program to ensure confidence and simplicity in an increasingly complex program. We also received comments that EMTS implementation with RFS2 is necessary so industry would not have to create a new system to handle RFS2 RINs for 2010 and then move to EMTS for 2011 while still handling RFS1 RINs. Potentially, three RIN transaction systems would exist during transition from RFS1 to RFS2 if EMTS could not be implemented with the start of the RFS2 program. EPA agrees that this three system issue would be an undue burden to industry as it would require industry to create two systems within a 12 month period. EMTS development started with the introduction of the NPRM, and has been in beta testing since early November with a select group of different industry stakeholders. Industry feedback has been overwhelmingly strong for the implementation of EMTS with the start of RFS2. With this final rule, EPA decided that EMTS will start on the same date when RFS2 RINs are required to be generated. In addition, to ensure that parties will have enough time to incorporate RFS2 and EMTS requirements into private RIN tracking systems, the generation of RFS2 RINs will begin on July 1, 2010. Therefore, all RFS regulated parties are required to use EMTS starting July 1, 2010.

RIN transactions are required to be verified and certified on a quarterly basis. EMTS will provide summaries for parties to verify, report, and certify transactions to EPA through the fuels reporting system, DCFuels. Additional information may be required to be added to the EMTS provided summary. This additional certification step allows parties to verification that the information sent to EMTS is accurate. However, parties may choose to review their data by checking their EMTS account at anytime.

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3. How EMTS Will Work

EMTS will be a closed, EPA-moderated system that provides a mechanism for screening RINs and a structured environment for conducting RIN transactions. "Screening" of RINs means that parties can have greater confidence that the RINs they handle are genuine. Although screening cannot remove all human error, we believe it can remove most of it.

We received comments opposing the 3 day time window for reporting transactions to the EMTS. One commenter requested 7 days from the event for sellers to report a transaction and 7 days after that for the buyer to accept the transaction. In order for this to be a "real time" system, we must require that the information comes in a timely manner. One commenter requested 10 days from the event to send information to EMTS. EPA has concluded that five days, or a business week, is an appropriate amount of time for both parties to receive or provide necessary documentation in order to interact with EMTS accurately and timely. "Real time" will be defined as within five (5) business days of a reportable event (e.g., generation and assignment of RINs, transfer of RINs).

Parties who use EMTS must first register with EPA in accordance with the RFS2 registration program described in Section II.C of this preamble. Parties will also have to create an account (i.e., register) via EPA's Central Data Exchange (CDX), as users will access EMTS via CDX. CDX is a secure and central electronic portal through which parties may submit compliance reports. Parties must establish an account with EMTS by July 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later. Once registration occurs, individual accounts will be established within EMTS and the system will enable a party to submit transactions based on their registration information.

In EMTS, the screening and assignment of RINs will be made at the logical point, i.e., the point when RINs are generated through production or importation of renewable fuel. A renewable producer will electronically submit, in "real time," a volume of renewable fuel produced or imported, as well as a number of the RINs generated and assigned. EMTS will automatically screen each batch and either reject the information or allow RINs created in the RIN generator's account as one of the five types of RINs.

We received comments supporting the RFS1 approach that allows producers and importers to generate RINs at the renewable fuel point of sale. EPA realizes that this is an industry practice and this flexibility will still be allowed for RIN generators, but only if applied consistently.

After RINs have entered the system, parties may then trade them based on agreements outside of EMTS. One major advantage of EMTS, over the RFS1 system, is that the system will simplify trading by allowing RINs to be traded generically. Only some specifying information will be needed to trade RINs, such as RIN quantity, fuel type, RIN assignment, RIN year, RIN price or price per gallon. The unique identification of the RIN will exist within EMTS, but parties engaging in RIN transactions will no longer have to worry about incorrectly recording or using 38-digit RIN numbers. The actual items of transactional information covered under RFS2 are very similar to those reported under RFS1. The RIN price is one of the new pieces of transactional information required to be submitted under RFS2.

We received several adverse comments strongly opposing the collection of price information due to Confidential Business Information (CBI) concerns, other services being able to provide this information, marketplace delays and undue stress on the EMTS from disagreements in RIN price. We received one comment strongly supporting EPA collecting this information. EPA decided that the price information has great programmatic value because it will help us anticipate and appropriately react to market disruptions and other compliance challenges, assess and develop responses to potential waivers, and assist in setting future renewable fuel standards. In addition, EPA decided that highly summarized price information (e.g., the average price of RINs traded nationwide) may be valuable to regulated parties, as well, and may help them to anticipate and avoid market disruptions. Also, EPA will not require the matching of the exact RIN price to alleviate the burden of resubmission due to price mistakes. However, the price information must be accurate and rounded to the nearest cent (US Dollar) at the time of sending the transactional information to EMTS.

We received one comment requesting publication of security precautions taken by EPA to protect EMTS from attacks. EPA cannot provide security information to the public because providing such information may create security vulnerabilities. However, EMTS will be compliant with the appropriate security requirements for all federal agency information technology systems.

Also as with RFS1, there is no “good faith” provision to RIN ownership. An underlying principle of RIN ownership is still one of "buyer beware" and RINs may be prohibited from use at any time if they are found to be invalid. Because of the “buyer beware” aspect, we will offer the option for a buyer to accept or reject RINs from specific RIN generators or from classes of RIN generators.

4. A Sample EMTS Transaction

This sample illustrates how two parties may trade RINs in EMTS:

1) Seller logs into EMTS and posts a sale of 10,000 RINs to Buyer at X price. For this example, assume the RINs were generated in 2010 and were assigned to 10,000 gallons of “Renewable fuel (D=6)”. Seller’s RIN account for “Renewable fuel (D=6)” is put into a “pending” status of 10,000 with the posting of the sale to Buyer. Buyer receives automatic notification of the pending transaction.

2) Buyer logs into EMTS. Buyer sees the sale transaction pending. Assuming it is correct, Buyer accepts it. Upon acceptance, Buyer’s RIN account for “Renewable fuel (D=6)” RINs is automatically increased by 10,000 2010 assigned RINs sold at X price.

3) After Seller has posted the sale and Buyer has accepted it, EMTS automatically notifies both Buyer and Seller that the transaction has been fully completed.

Under EMTS, the seller will always have to initiate any transaction. The specific amount of RINs are put into a pending status when the seller posts the sale. The buyer must confirm the sale in order to have the RINs transferred to the buyer’s account. Transactions will always be limited to available RINs. Notification will automatically be sent to both the buyer and the seller upon completion of the transaction. EPA considers any sale or transfer as complete upon acknowledgement by the buyer. We will also allow buyers to submit their acknowledgement prior to a seller initiating the transaction. However, these buy transactions will not initiate any RINs being put into a pending status from a seller’s account. Instead, the buy transactions will be queued and checked periodically to see if a “sell” transaction was posted by the seller. If a buy is posted without a matching sell transaction, then the seller will be notified that a buy transaction is pending. Both buy and sell transactions must be matched within a set number of days from the submission date or they will expire. Transactions will expire 7 days after the submission of the file. Since both parties are required to submit information within 5 days, we allow the full 5 days to expire plus 2 days in the case of late submissions.

In summary, the advantage to implementing EMTS is that parties may engage in RIN transactions with a high degree of confidence, errors will be virtually eliminated, and everyone engaging in RIN transactions will have a simplified environment in which to work, which should minimize the level of resources needed for implementation.

B. Upward Delegation of RIN-Separating Responsibilities

Since the start of the RFS program on September 1, 2007, there have been a number of instances in which a party who receives RINs with a volume of renewable fuel is required to either separate or retire those RINs, but views the recordkeeping and reporting requirements under the RFS program as an unnecessary burden. Such circumstances typically might involve a renewable fuel blender, a party that uses renewable fuel in its neat form, or a party that uses renewable fuel in a non-highway application and is therefore required to retire the RINs (under RFS1) associated with the volume. In some of these cases, the affected party may purchase and/or use only small volumes of renewable fuel and, absent the RFS program, would be subject to few (if any other) EPA regulations governing fuels.

This situation will become more prevalent with the RFS2 rule, as EISA added diesel fuel to the RFS program. With the RFS1 rule, small blenders (generally farmers and other parties that use nonroad diesel fuel) blending small amounts of biodiesel were not covered under the rule as EPAct mandated renewable fuel blending for highway gasoline only. EISA mandates certain amounts of renewable fuels to be blended into all transportation fuels—which includes highway and nonroad diesel fuel. Thus, parties that were not regulated under the RFS1 rule who only blend a small amount of renewable fuel (and, as mentioned above, are generally not subject to EPA fuels regulations) will now be regulated by the RFS program.

Consequently, we believe it is appropriate, and thus we are finalizing as proposed, to permit blenders who only blend a small amount of renewable fuel to allow the party directly upstream to separate RINs on their behalf. Such a provision is consistent with the fact that the RFS program already allows marketers of renewable fuels to assign more RINs to some of their sold product and no RINs to the rest of their sold product. We believe that this provision will eliminate undue burden on small parties who would otherwise not be regulated by this program. This provision is solely for the case of blenders who blend and trade less than 125,000 total gallons of renewable fuel per year (i.e., a company that blends 100,000 gallons and trades another 100,000 gallons would not be able to use this provision) and is available to any blender who must separate RINs from a volume of renewable fuel under §80.1429(b)(2).

We requested comment in the NPRM on this concept, the 125,000 gallon threshold, and appropriate documentation to authorize this upward delegation. In general, those that commented on this provision support the idea of upward delegation for small blenders, though one commenter stated that EPA should not allow small entities to delegate their RIN-related responsibilities upward. Those commenters that support the upward delegation provision stated that it should be limited to small blenders only and should only be for delegating to the party directly upstream. A few commenters stated that they believe the 125,000 gallon threshold is appropriate; while others commented that it should be higher. We believe that the 125,000 gallon limit strikes the correct balance between providing relief to small blenders, while still ensuring that non-obligated parties cannot unduly influence the RIN market.

We did not receive any comments on appropriate documentation, however a couple commenters suggested that we retain the proposed annual authorization between the blender and the party directly upstream, as well as allowing a small blender to enter into arrangements with multiple suppliers on a transaction-by-transaction basis. Please see Chapter 5 of the Summary and Analysis of Comments Document for more discussion on the comments received and our responses to those comments.

We are also finalizing, as stated in the preamble to the proposed rule, that for upstream delegation, both parties must sign a quarterly written statement (which must be included with the reporting party's reports) authorizing the upward delegation. Copies of these statements must be retained as records by both parties. The supplier would then be allowed to retain ownership of RINs assigned to a volume of renewable fuel when that volume is transferred, under the condition that the RINs be separated or retired concurrently with the transfer of the volume. This statement would apply to all volumes of renewable fuel transferred between the two parties. Thus, the two parties would enter into a contract stating that the supplier has RIN-separation responsibilities for all transferred volumes between the two parties, and no additional permissions from the small blender would be needed for any volumes transferred. A blender may enter into such an agreement with as many parties as they wish.

C. Small Producer Exemption

Under the RFS1 rule, parties who produce or import less than 10,000 gallons of renewable fuel in a year are not required to generate RINs for that volume, and are not required to register with the EPA if they do not take ownership of RINs generated by other parties. These producers and importers are also exempt from registration, reporting, recordkeeping, and attest engagement requirements. In the preamble to the proposed rule, we requested comment on whether or not this 10,000 gallon threshold was appropriate. One commenter suggested that we retain the 10,000 gallon threshold as-is. Another commenter supported the concept of less burdensome requirements for small producers, but suggested that these entities should, at a minimum, be required to generate RINs for all qualifying renewables. We are maintaining this exemption under the RFS2 rule for parties who produce or import less than 10,000 gallons of renewable fuel per year.

In addition to the permanent exemption for those producers and importers who produce or import less than 10,000 gallons of renewable fuel per year, we are also finalizing a temporary exemption for renewable fuel producers who produce less than 125,000 gallons of renewable fuel each year from new production facilities. These producers are not required to generate and assign RINs to batches of renewable fuel for a period of up to three years, beginning with the calendar year in which the production facility produces its first gallon of renewable fuel. Such producers are also exempt from registration, reporting, recordkeeping, and attest engagement requirements as long as they do not own RINs or voluntarily generate and assign RINs. This provision is intended to allow pilot and demonstration plants of new renewable fuel technologies to focus on developing the technology and obtaining financing during these early stages of their development without having to comply with the RFS2 regulations.

D. 20% Rollover Cap

EISA does not change the language in CAA section 211(o)(5) stating that renewable fuel credits must be valid for showing compliance for 12 months as of the date of generation. As discussed in the RFS1 final rulemaking, we interpreted the statute such that credits would represent renewable fuel volumes in excess of what an obligated party needs to meet their annual compliance obligation. Given that the renewable fuel standard is an annual standard, obligated parties determine compliance shortly after the end of the year, and credits would be identified at that time. In the context of our RIN-based program, we have accomplished the statute's objective by allowing RINs to be used to show compliance for the year in which the renewable fuel was produced and its associated RIN first generated, or for the following year. RINs not used for compliance purposes in the year in which they were generated will by definition be in excess of the RINs needed by obligated parties in that year, making excess RINs equivalent to the credits referred to in section 211(o)(5). Excess RINs are valid for compliance purposes in the year following the one in which they initially came into existence. RINs not used within their valid life will thereafter cease to be valid for compliance purposes.

In the RFS1 final rulemaking, we also discussed the potential "rollover" of excess RINs over multiple years. This can occur in situations wherein the total number of RINs generated each year for a number of years in a row exceeds the number of RINs required under the RFS program for those years. The excess RINs generated in one year could be used to show compliance in the next year, leading to the generation of new excess RINs in the next year, causing the total number of excess RINs in the market to accumulate over multiple years despite the limit on RIN life. When renewable fuel volumes are being produced that exceed the RFS2 standards, the rollover issue could undermine the ability of a limit on credit life to guarantee an ongoing market for renewable fuels.

To implement EISA's restriction on the life of credits and address the rollover issue, the RFS1 final rulemaking implemented a 20% cap on the amount of an obligated party's RVO that can be met using previous-year RINs. Thus each obligated party is required to use current-year RINs to meet at least 80% of its RVO, with a maximum of 20% being derived from previous-year RINs. Any previous-year RINs that an obligated party may have that are in excess of the 20% cap can be traded to other obligated parties that need them. If the previous-year RINs in excess of the 20% cap are not used by any obligated party for compliance, they will thereafter cease to be valid for compliance purposes.

As described in the NPRM, EISA does not modify the statutory provisions regarding credit life, and the volume changes by EISA also do not change at least the possibility of large rollovers of RINs for individual obligated parties. As a result we proposed to maintain the regulatory requirement for a 20% rollover cap under the new RFS2 program, and to apply this cap separately to all four RVOs under RFS2. However, we took comment on changing the level of the cap to some alternative value lower or higher than 20%.

A lower cap could provide a greater incentive for parties with excess RINs to sell them rather than hold onto them, increasing the availability of RINs for parties that need them for compliance purposes. But a lower cap would also reduce flexibility for obligated parties attempting to minimize the costs of compliance with increasing annual volume requirements, particularly if there are concerns that the RIN market may be tighter in the future than it is currently.

Conversely, the increasing annual volume requirements in EISA make it less likely that renewable fuel producers will overcomply, and as a result it is less likely that there will be an excess of RINs in the market. Under these circumstances, there is little opportunity for RINs to build up in the market, and the rollover cap would have less of an impact on the market as a whole. Thus a higher cap might be warranted. However, while a higher cap would create greater flexibility for some obligated parties, it could also create disruptions in the RIN market as parties with excess RINs would have a greater opportunity to hold onto them rather than sell them. Parties without direct access to RINs through the purchase and blending of renewable fuels would be placed at a competitive disadvantage in comparison to parties with excess RINs. In the extreme, removal of the cap entirely would allow obligated parties to roll over up to one year's worth of their obligations indefinitely.

In general, commenters on the NPRM reiterated the positions that they raised during development of the RFS1 program. While one renewable fuel producer requested that the rollover cap be left at 20%, most producers requested that the rollover cap be reduced to 0%, such that compliance with the standards applicable in a given year could only be demonstrated using RINs generated in that year. In contrast, refiners requested that the rollover cap be either eliminated, such that any number of previous year RINs could be used for current year compliance, or at least raised to 40 or 50 percent. Small refiners requested that the cap be raised for small refiners only to accommodate the competitive disadvantage with respect to the RIN market that they believe they experience in comparison to larger refiners.

Based on the comments received, we believe that the 20% level continues to provide the appropriate balance between, on the one hand, allowing legitimate RIN carryovers and protecting against potential supply shortfalls that could limit the availability of RINs, and on the other hand ensuring an annual demand for renewable fuels as envisioned by EISA. Therefore, we are continuing the 20% rollover cap for obligated parties for the RFS program.

E. Small Refinery and Small Refiner Flexibilities

This section discusses flexibilities for small refineries and small refiners for the RFS2 rule. As explained in the discussion of our compliance with the Regulatory Flexibility Act below in Section XI.C and in the Final Regulatory Flexibility Analysis in Chapter 7 of the RIA, we considered the impacts of the RFS2 regulations on small businesses (small refiners). Most of our analysis of small business impacts was performed as a part of the work of the Small Business Advocacy Review Panel (SBAR Panel, or “the Panel”) convened by EPA for this rule, pursuant to the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The Final Report of the Panel is available in the rulemaking docket. For the SBREFA process, we conducted outreach, fact-finding, and analysis of the potential impacts of our regulations on small business refiners.

1. Background- RFS1

a. Small Refinery Exemption

CAA section 211(o)(9), enacted as part of EPAct, provides a temporary exemption to small refineries (those refineries with a crude throughput of no more than 75,000 barrels of crude per day, as defined in section 211(o)(1)(K)) through December 31, 2010[35]. Accordingly, the

[35] Small refineries are also allowed to waive this exemption.

RFS1 program regulations exempt gasoline produced by small refineries from the renewable fuels standard (unless the exemption was waived), see 40 CFR 80.1141. EISA did not alter the small refinery exemption in any way.

b. Small Refiner Exemption

As mentioned above, EPAct granted a temporary exemption from the RFS program to small refineries through December 31, 2010. In the RFS1 final rule, we exercised our discretion under section 211(o)(3)(B) and extended this temporary exemption to the few remaining small refiners that met the Small Business Administration's (SBA) definition of a small business (1,500 employees or less company-wide) but did not meet the EPAct small refinery definition as noted above.

2. Statutory Options for Extending Relief

There are two provisions in section 211(o)(9) that allow for an extension of the temporary exemption for small refineries beyond December 31, 2010.

One provision involves a study by the Department of Energy (DOE) concerning whether compliance with the renewable fuel requirements would impose disproportionate economic hardship on small refineries, and would grant an automatic extension of at least two years for small refineries that DOE determines would be subject to such disproportionate hardship (per section 211(o)(9)(A)(ii)). If the DOE study determines that such hardship exists, then section 211(o)(9)(A)(ii) (which was retained in EISA) provides that EPA shall extend the exemption for a period of at least two years.

The second provision, at section 211(o)(9)(B), authorizes EPA to grant an extension for a small refinery based upon disproportionate economic hardship, on a case-by-case basis. A small refinery may, at any time, petition EPA for an extension of the small refinery exemption on the basis of disproportionate economic hardship. EPA is to consult with DOE and consider the findings of the DOE small refinery study in evaluating such petitions. These petitions may be filed at any time, and EPA has discretion to determine the length of any exemption that may be granted in response.

3. The DOE Study/DOE Study Results

As discussed above, EPAct required that DOE perform a study by December 31, 2008 on the impact of the renewable fuel requirements on small refineries (section 211(o)(9)(A)(ii)(I)), and whether or not the requirements would impose a disproportionate economic hardship on these refineries. In the small refinery study, "EPACT 2005 Section 1501 Small Refineries Exemption Study", DOE's finding was that there is no reason to believe that any small refinery would be disproportionately harmed by inclusion in the proposed RFS2 program. This finding was based on the fact that there appeared to be no shortage of RINs available under RFS1, and EISA has provided flexibility through waiver authority (per section 211(o)(7)). Further, in the case of the cellulosic biofuel standard, cellulosic biofuel allowances can be provided from EPA at prices established in EISA (see regulation section 80.1456). DOE thus determined that small refineries would not be subject to disproportionate economic hardship under the proposed RFS2 program, and that the exemption should not, on the basis of the study, be extended for small refineries (including those small refiners who own refineries meeting the small refinery definition) beyond December 31, 2010. DOE noted in the study that, if circumstances were to change and/or the RIN market were to become non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption (pursuant to Section 211(o)(9)(B)).

4. Ability to Grant Relief Beyond 211(o)(9)

The SBREFA panel made a number of recommendations for regulatory relief and additional flexibility for small refineries and small refiners. These are described in the Final Panel Report (located in the rulemaking docket), and summarized below. During the development of this final rule, we again evaluated the various options recommended by the Panel and also comments on the proposed rule. We also consulted the small refinery study prepared by DOE.

As described in the Final Panel Report, EPA early-on identified limitations on its authority to issue additional flexibility and exemptions to small refineries. In section 211(o)(9) Congress specifically addressed the issue of an extension of time for compliance for small refineries, temporarily exempting them from renewable fuel obligations through December 31, 2010. As discussed above, the statute also includes two specific provisions describing the basis and manner in which further extensions of this exemption can be provided. In the RFS1 rulemaking, EPA considered whether it should provide additional relief to the limited number of small refiners who were not covered by the small refinery provision, by providing them a temporary exemption consistent with that provided by Congress for small refineries. EPA exercised its discretion under section 211(o)(3) and provided such relief. Thus, in RFS1, EPA did not modify the relief provided by Congress for small refineries, but did exercise its discretion to provide the same relief specified by statute to a few additional parties.

In RFS2 we are faced with a different issue—the extent to which EPA should provide additional relief to small refineries beyond the relief specified by statute, and whether it should provide such further relief to small refiners as well. There is considerable overlap between entities that are small refineries and those that are small refiners. Providing additional relief just to small refiners would, therefore, also extend additional relief to at least a number of small refineries. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited that relief to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by Congress are met. EPA believes that an additional or different extension, relying on a more general provision in section 211(o)(3) would be inconsistent with Congressional intent. Further, we do not believe that the statute allows us the discretion to give relief to small refiners only—as this would result in a subset of small refineries (those that also qualify as small refiners) receiving relief that is greater than the relief already given to all small refineries under EISA.

EPA also notes that the criteria specified by statute for providing a further compliance extension to small refineries is a demonstration of "disproportionate economic hardship." The statute provides that such hardship can be identified through the DOE study, or in individual petitions submitted to the Agency. However, the DOE study has concluded that no disproportionate economic hardship exists, at least under current conditions and for the foreseeable future under RFS2. Therefore, absent further information that may be provided through the petition process, there does not currently appear to be a basis under the statute for granting further compliance extensions to small refineries. If DOE revises its study and comes to a different conclusion, EPA can revisit this issue.

5. Congress-Requested Revised DOE Study

In their written comments, as well as in discussions we had with them on the proposed rule, small refiners indicated that they did not believe that EPA should rely on the results of the DOE small refinery study to inform any decisions on small refiner provisions. Small refiners generally commented that they believe that the study was flawed and that the conclusions of the study were reached without adequate analysis of, or outreach with, small refineries (as the majority of the small refiners own refineries that meet the Congressional small refinery definition). One commenter stated that such a limited investigation into the impact on small refineries could not have resulted in any in-depth analysis on the economic impacts of the program on these entities. Another commenter stated that it believes that DOE should be directed to reopen and reassess the small refinery study be June 30, 2010, as suggested by the Senate Appropriations Committee.

We are aware that there have been expressions of concern from Congress regarding the DOE Study. Specifically, in Senate Report 111-45, the Senate Appropriations Committee "directed [DOE] to reopen and reassess the Small Refineries Exemption Study by June 30, 2010," noting a number of factors that the Committee intended that DOE consider in the revised study. The Final Conference Report 111-278 to the Energy & Water Development Appropriations Act (H.R. 3183), referenced the language in the Senate Report, noting that the conferees "support the study requested by the Senate on RFS and expect the Department to undertake the requested economic review." At the present time, however, the DOE study has not been revised. If DOE prepares a revised study and the revised study finds that there is a disproportionate economic impact, we will revisit the exemption extension at that point in accordance with section 211(o)(9)(A)(ii).

6. What We're Finalizing

a. Small Refinery and Small Refiner Temporary Exemptions

As mentioned above, the RFS1 program regulations exempt gasoline produced by small refineries from the renewable fuels standard through December 31, 2010 (at 40 CFR 80.1141), per EPAct. As EISA did not alter the small refinery exemption in any way, we are retaining this small refinery temporary exemption in the RFS2 program without change (except for the fact that all transportation fuel produced by small refineries will be exempt, as EISA also covers diesel and nonroad fuels).

Likewise, as we extended under RFS1 the small refinery temporary exemption to the few remaining small refiners that met the Small Business Administration's (SBA) definition of a small business (1,500 employees or less company-wide), we are also finalizing a continuation of the small refiner temporary exemption through December 31, 2010.

b. Case-by-Case Hardship for Small Refineries and Small Refiners

As discussed in Section III.E.2, EPAct also authorizes EPA to grant an extension for a small refinery based upon disproportionate economic hardship, on a case-by-case basis. We believe that these avenues of relief can and should be fully explored by small refiners who are covered by the small refinery provision. In addition, we believe that it is appropriate to allow petitions to EPA for an extension of the temporary exemption based on disproportionate economic hardship for those small refiners who are not covered by the small refinery provision (again, per our discretion under section 211(o)(3)(B)); this would ensure that all small refiners have the same relief available to them as small refineries do. Thus, we are finalizing a hardship provision for small refineries in the RFS2 program, that any small refinery may apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per CAA section 211(o)(9)(B). We are also finalizing a case-by-case hardship provision for those small refiners that do not operate small refineries using our discretion under CAA section 211(o)(3)(B). This provision will allow those small refiners that do not operate small refineries to apply for the same kind of hardship extension as a small refinery. In evaluating applications for this hardship provision EPA will take into consideration information gathered from annual reports and RIN system progress updates, as recommended by the SBAR Panel, as well as information provided by the petitioner and through consultation with DOE.

c. Program Review

During the SBREFA process, the small refiner Small Entity Representatives (SERs) also requested that EPA perform an annual program review, to begin one year before small refiners are required to comply with the program, to provide information on RIN system progress. As mentioned in the preamble to the proposed rule, we were concerned that such a review could lead to some redundancy with the notice of the applicable RFS standards that EPA will publish in the Federal Register annually, and this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, some Panel members commented that they believe a program review could be beneficial to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As we will be publishing a Federal Register notice annually, the Panel recommended, and we proposed, that an update of RIN system progress (e.g., RIN trading, publicly-available information on RIN availability, etc.) be included in this annual notice.

Based on comments received on the proposed rule, we believe that such information could be helpful to industry, especially to small businesses to help aid the proper functioning of the RIN market, especially in the first years of the program. However, during the development of the final rule, it became evident that there could be instances where we would want to report out RIN system information on a more frequent basis than just once a year. Thus we are finalizing that we will periodically report out elements of RIN system progress; but such information will be reported via other means (e.g., the RFS website (www.epa.gov/otaq/renewablefuels/index.htm), EMTS homepage, etc.).

7. Other Flexibilities Considered for Small Refiners

During the SBREFA process, and in their comments on the proposed rule, small refiners informed us that they would need to rely heavily on RINs and/or make capital improvements to comply with the RFS2 requirements. These refiners raised concerns about the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and costs), the desire for an annual RIN system review, and the difficulty in raising capital and competing for engineering resources to make capital improvements.

The Panel recommended that EPA consider the issues raised by the small refiner SERs and discussions had by the Panel itself, and that EPA should consider comments on flexibility alternatives that would help to mitigate negative impacts on small businesses to the extent allowable by the Clean Air Act. A summary of further recommendations of the Panel are discussed in Section XI.C of this preamble, and a full discussion of the regulatory alternatives discussed and recommended by the Panel can be found in the SBREFA Final Panel Report. Also, a complete discussion of comments received on the proposed rule regarding small refinery and small refiner flexibilities can be found in Chapter 5 of the Summary and Analysis of Comments document.

a. Extensions of the RFS1 Temporary Exemption for Small Refiners

As previously stated, the RFS1 program regulations provide small refiners who operate small refineries, as well as those small refiners who do not operate small refineries, with a temporary exemption from the standards through December 31, 2010. This provided an exemption for small refineries (and small refiners) for the first five years of the RFS program. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the RFS standards as increased by Congress in EISA. The Panel recommended that EPA propose a delay in the effective date of the standards until 2014 (for a total of eight years) for small entities, to the extent allowed by the statute.

During the development of both the Final Panel Report and the proposed rule, we evaluated various options for small refiners, including an additional temporary exemption for small refiners from the required RFS2 standards. As discussed above, we concluded that we do not have the statutory authority to provide such extensions through means other than those specified in the statute. Thus, further extensions will be as a result of any revised DOE study, or in response to a petition, pursuant to the authorities specified in section 211(o)(9).

We proposed to continue the temporary exemption finalized in RFS1—through December 31, 2010. Commenters that oppose an extension of the temporary exemption generally stated that an extension is not warranted, and some commenters expressed concerns about allowing provisions for small refiners. One commenter also stated that it believes that the small refinery exemption should not be extended and that the small refiner exemption should be eliminated completely. Two commenters supported the continuation of the exemption through

December 31, 2010 only, and one stated that it does not support an extension as it believes that all parties have been well aware of the passage of EISA and small refineries and small refiners should have been striving to achieve compliance by the end of 2010. Two commenters also expressed views that the exemption should not have been offered to small refiners in RFS1 as this was not provided by EPAct, and that an extension of the exemption should not be finalized for small refineries at all. The commenters further commented that an economic hardship provision was included in EPAct, and any exemption extension should be limited to such cases, and only to the specific small refinery (not small refiner) that has petitioned for such an extension.

Commenters supporting an extension of the exemption commented that they believe that the statutes (EPAct and EISA) do not prohibit EPA from providing relief to regulated small entities on which the rule will have a significant economic impact, and that such a delay could lessen the burden on these entities. One commenter stated that it believes EPA denied or ignored much of the relief recommended by the Panel in the proposal. Another commenter stated that it believes EPA's concerns regarding the legal authority are unsustainable considering EPA's past exercises of discretion under the RFS1 program, and with the discretion afforded to EPA under section 211(o) of the CAA. Some commenters requested a delay until 2014 for small refiners. One additional commenter expressed support for an extension of the small refinery exemption only, and that these small refineries should be granted a permanent exemption.

During the development of this final rule, we again evaluated the various options recommended by the Panel, the legality of offering an extension of the exemption to small refiners only, and also comments on the proposed rule. Specifically in the case of an extension of the exemption for small refiners, we also consulted the small refinery study prepared by DOE, as the statute directs us to use this as a basis for providing an additional two year exemption. As discussed above in Sections III.E.4 and 5, we do not believe that we can provide an extension of the exemption considering the outcome of the DOE small refinery study, which did not find that there was a disproportionate economic hardship. Further, we do not believe that the statute allows us the discretion to give relief to a subset of small refineries (those that also qualify as small refiners) that is greater than the relief already given to all small refineries under EPAct. However, it is important to recognize that the 211(o)(9) small refinery provision does allow for extensions beyond December 31, 2010, as discussed above in Section III.E.2. Thus, refiners may apply for individual hardship relief.

b. Phase-in

The small refiner SERs suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards. However we stated in the NPRM that we had serious concerns about our legal authority to provide such a phase-in. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall "consist of a single applicable percentage that applies to all categories of persons specified" as obligated parties. A phase-in approach would essentially result in different applicable percentages being applied to different obligated parties.

Further, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the statutory small refinery provisions.

Some commenters stated that they believe that EPA has the ability to consider a phase-in of the standards for small refiners. One commenter suggested that a temporary phase-in could help lessen the burden of regulation on small entities and promote compliance. Another commenter stated that it believes EPA's legal concerns regarding a phase-in are unsustainable considering EPA's past exercises of discretion under the RFS1 program and with the discretion afforded to EPA under section 211(o) of the CAA.

After considering the comments on this issue, EPA continues to believe that allowing a phase-in of regulatory requirements for small refineries and/or small refiners would be inconsistent with the statute, for the reasons mentioned above. Any individual entities that are experiencing hardship that could justify a phase-in of the standards have the ability to petition EPA for individualized relief. Therefore we are not including a phase-in of standards for small refiners in today's rule.

c. RIN-Related Flexibilities

The small refiner SERs requested that the RFS2 rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing small refiners only to use RINs interchangeably. In the RFS1 rule, up to 20% of a previous year's RINs may be "rolled over" and used for compliance in the following year. In the preamble to the proposed rule, we discussed the concept of allowing for flexibilities in the rollover cap, such as a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. As the rollover cap is the means through which we are implementing the limited credit lifetime provisions in section 211(o) of the CAA, and therefore cannot simply be eliminated, we requested comment on the concept of increasing the RIN rollover cap percentage for small refiners and an appropriate level of that percentage. In response to the Panel's recommendation, we also sought comment on allowing small refiners to use the four types of RINs interchangeably.

In their comments on the proposed rule, one small refiner commented that, in regards to small refiners' concerns about RIN pricing and availability, there is no mechanism in the rule to address the possibility that the RIN market will not be viable. The commenter further suggested that more "durable" RINs are needed for small refiners that can be carried over from year to year, to alleviate some of the potentially market volatility for renewable fuels. Another commenter suggested that RINs should be interchangeable for small refiners, or alternatively, some mechanism should be implemented to ensure that RIN prices are affordable for small refiners. Further, with regard to interchangeable RINs, one commenter stated that small refiners do not have the staff or systems to manage and account for four different categories of RINs and rural small refiners will suffer economic hardship and disadvantage because of the unavailability of biofuels. The commenter also requested an increase in the rollover cap to 50% for small refiners.

We are not finalizing additional RIN-related flexibilities for small refiners in today's action. As highlighted in the NPRM, we continue to believe that the concept of interchangeable RINs for small refiners only fails to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel), and is not consistent with section 211(o) of the Clean Air Act. Essentially, it would circumvent the explicit direction of Congress in EISA to require that the four RFS2 standards be met separately. Further, given the findings from the DOE study that small refineries (and thus, most small refiners) do not currently face disproportionate economic hardship, and are not expected to do so as RFS2 is implemented, we do not believe that a basis exists to justify providing small refiners with a larger rollover cap than other regulated entities. Thus, small refiners will be held to the same RIN rollover cap as other obligated parties.

F. Retail Dispenser Labeling for Gasoline with Greater than 10 Percent Ethanol

We proposed labeling requirements for fuel dispensers that handle greater than 10 volume percent ethanol blends which included the following text: For use only in flexible-fuel vehicles, May damage non-flexible-fuel vehicles, Federal law prohibits use in non-flexible-fuel vehicles. This proposal was primarily meant to help address concerns about the potential misfueling of non-flex-fuel vehicles with E85, in light of the anticipated increase in E85 sales volumes in response to the RFS2 program. All ethanol blends above 10 volume percent were included due to the increasing industry focus on ethanol blender pumps that are designed to dispense a variety of ethanol blends (e.g., E30, and E40) for use in flex-fuel vehicles.

Commenters stated that EPA should undertake additional analysis of the potential impacts from misfueling and what preventative measures might be appropriate before finalizing labeling requirements for >E10 blends. They also stated that EPA should coordinate any such labeling provisions with those already in place by the Federal Trade Commission. EPA is also currently evaluating a petition to allow the use of up to 15 volume percent ethanol in non-flex fuel vehicles. One potential result of this evaluation might be for EPA to grant a partial waiver that is applicable only for a subset of the current vehicle population. Under such an approach, a label for E15 fuel dispensers would be needed that identifies what vehicles are approved to use E15.

Based on the public comments and the fact that EPA has not completed its evaluation of the E15 waiver petition, we believe that it is appropriate to defer finalizing labeling requirements for >E10 blends at this time. This will afford us the opportunity to complete our analysis of what measures might be appropriate to prevent misfueling with >E10 blends before this may become a concern in the context of the RFS2 program.

G. Biodiesel Temperature Standardization

The volume of a batch of renewable fuel can change under extreme changes in temperature. The volume of a batch of renewable fuel can experience expansion as the temperature increases, or can experience contraction as temperature decreases. The Agency requires temperature standardization of renewable fuels at 60 ° Fahrenheit (°F) so renewable fuel volumes are accounted for on a uniform and consistent basis over the entire fuels industry. In the May 1, 2007 Renewable Fuels Standard (RFS) final rule the Agency required biodiesel temperature standardization to be completed as follows:

$$V_{s,b} = V_{a,b} \times (-0.0008008 \times T + 1.0480)$$

Where

$V_{s,b}$ = Standard Volume of biodiesel at 60 degrees F, in gallons;
$V_{a,b}$ = Actual volume of biodiesel, in gallons;
T = Actual temperature of batch, in degrees F.

This equation was based on data from a published research paper by *Tate et al.* [36] Members of the petroleum industry have indicated that the current biodiesel temperature standardization equation in the regulations provides different results than that commonly used by both the petroleum and biodiesel industry for commercial trading of biodiesel. These commercial values are either based on American Petroleum Institute (API) tables for petroleum products or on empirical values from industry measurements at common temperatures and pressures observed in bulk fuel facilities. The difference between RIN calculated volumes and commercial sales volumes has created confusion within the record keeping system of both the petroleum and biodiesel industry.

In the RFS2 proposed rule, the Agency proposed the temperature standardization of biodiesel remain unchanged from the RFS1 requirements.[37] The Agency received comments from Archer Daniels Midland Company (ADM), World Energy Alternatives, Marathon Petroleum Company (Marathon) and the National Biodiesel Board (NBB) to revise the biodiesel temperature standardization equation.

Both ADM and NBB agreed on the necessity for biodiesel temperature standardization at 60 °F. ADM and NBB commented on several empirical calculations which have been developed specific to biodiesel temperature standardization since the 2007 RFS1 final rule. These include a 2004 data set developed by the Minnesota Department of Commerce and the Renewable Energy Group and updated in 2008; information embedded in the European Biodiesel Specification EN 14214; and information from the Alberta Research Council. The table below provides values from NBB for 1000 gallons of biodiesel standardized to a temperature at 60 °F for these empirical calculations, along with the current EPA equation, and the American Petroleum Institute (API) Refined Products Table 6.

Table III.G-1
NBB Comparison of Biodiesel Temperature Standardization Calculations to 60°F for 1000 gallons of Biodiesel at 90°F

2007 EPA Biodiesel Formula	975.28 gallons

[36] Equation was derived from R.E. Tate et al. "The Densities of Three Biodiesel Fuels at Temperatures up to 300°C.", Department of Biological Engineering, Dalhousie University, April 2005. "Fuel 85 (2006) 1004-1009, Table 1 for soy methyl ester."

[37] 74 FR 24943, May 26, 2009.

2008 Minnesota (Hedman) data	986.270 gallons
API Refined Products Table 6 (biodiesel density @ 7.359)	986.625 gallons
Alberta Research Council	986.238 gallons
EN 14214 data	986.401 gallons
2004 Minnesota Renewable Energy Group data	986.830 gallons

As illustrated by the results from the above table, the values for the various biodiesel temperature standardization empirical calculations are within 1 gallon of agreement of each other for a 1000 gallon biodiesel batch, except for the current biodiesel temperature standardization equation in the regulations.

To ensure consistency in RIN generation, ADM commented EPA should adopt only one biodiesel temperature standardization calculation. ADM commented that all biodiesel temperature standardization calculations developed, including the API Refined Products Table 6, are in very close agreement with each other and the differences between them all are insignificant. They further commented the API Refined Products Table 6 has provided a uniform measurement of volume for years for the entire liquid fuels industry. Thus, ADM believes the API Refined Products Table 6 should be adopted for biodiesel to be consistent with the calculation of sales volumes. Finally ADM comments adoption of the API Refined Products Table 6 would allow for easier verification within the marketplace, eliminate the need for calculating one volume for sales and trades and another for RINs, and prevents the entire distribution network from facing the financial burden of reprogramming existing meters that already are based on the API Refined Products Table 6.

NBB commented that earlier surveys from its members indicate a fifty-fifty split between members using the API Refined Products Table 6 or some variation of the current EPA biodiesel formula for biodiesel temperature standardization. Some NBB members indicated that the API Refined Products Table 6 was more commonly used by the petroleum industry and embedded into the meters, pumps and accounting systems of the petroleum industry. Companies already using the API Refined Products Table 6 would have a reduction in required paperwork with RIN generation and tracking because already existing commercial documents could serve that purpose and they thus could eliminate or reduce their current dual tracking system. Other NBB members have already embedded the current EPA biodiesel equation within their accounting and sales systems and would like to continue using that type of biodiesel temperature standardization approach rather than the API Refined Products Table 6. The NBB recommended EPA revise its current equation in the regulations to the 2008 Hedman biodiesel temperature standardization equation. Thus, NBB commented EPA should provide flexibility to their members by allowing the use of either the API Refined Products Table 6 or the use of a biodiesel temperature standardization equation.

Marathon commented the regulations allow for the standardization of volume for other renewable fuels to be determined by an appropriate formula commonly accepted by the industry which may be reviewed by the EPA for appropriateness. They recommended that EPA extend this courtesy to biodiesel.

The Agency acknowledges that the current biodiesel temperature standardization equation is likely not correct for biodiesel temperature standardization at ambient temperatures observed in the fuel distribution system. Based on the comments received, the Agency is amending the regulations to allow for two ways for biodiesel temperature standardization: 1) the American Petroleum Institute Refined Products Table 6B, as referenced in ASTM D1250-08, entitled, "Standard Guide for Use of the Petroleum Measurement Tables", and 2) a biodiesel temperature standardization equation that utilizes the 2008 data generated by the Minnesota Department of Commerce and the Renewable Energy Group. These two methods for biodiesel temperature standardization are within one gallon of agreement of each other for a 1000 gallon biodiesel batch and thus in very close agreement. Both ADM and NBB acknowledged that the differences between these two methods are insignificant and the resulting corrected volumes from these two methods of calculation are within accuracy tolerances of any metered measurement. Thus, the Agency believes the allowance of both of these methods for biodiesel temperature standardization will increase flexibility while still providing for a consistent generation and accounting of biodiesel RINs over the entire fuel delivery system.

IV. Renewable Fuel Production and Use

An assessment of the impacts of increased volumes of renewable fuel must begin with an analysis of the kind of renewable fuels that could be used, the types and locations of their feedstocks, the fuel volumes that could be produced by a given feedstock, and any challenges associated with their use. This section provides an assessment of the potential feedstocks and renewable fuels that could be used to meet the Energy Independence and Security Act (EISA) and the rationale behind our projections of various fuel types to represent the control cases for analysis purposes. As new technologies, feedstocks, and fuels continue to develop on a daily basis, markets may appear differently from our projections. Although actual volumes and feedstocks may differ, we believe the projections made for our control cases are within the range of possible predictions for which the standards are met and allow for an assessment of the potential impacts of the increases in renewable fuel volumes that meet the requirements of EISA.

A. Overview of Renewable Fuel Volumes

EISA mandates the use of increasing volumes of renewable fuel. To assess the impacts of this increase in renewable fuel volume from business-as-usual (what is likely to have occurred without EISA), we have established reference and control cases from which subsequent analyses are based. The reference cases are projections of renewable fuel volumes without the enactment of EISA and are described in Section IV.A.1. The control cases are projections of the volumes and types of renewable fuel that might be used in the future to comply with the EISA volume mandates. For the NPRM we had focused on one primary control case (see Section IV.A.2) whereas for the final rule we have expanded the analysis to include two additional sensitivity cases (see Section IV.A.3). Based on the public comments received as well as new information, we have updated the primary control case volumes from the NPRM to reflect what we believe could be a more likely set of volumes to analyze. We assume in each of the cases the same ethanol-equivalence basis as was used in the RFS1 rulemaking to meet the standard. Volumes are listed in tables for this section in both straight-gallons and ethanol-equivalent gallons (i.e., times 1.5 for biodiesel or 1.7 for cellulosic diesel and renewable diesel). The volumes included in this section are for 2022. For intermediate years, refer to Section 1.2 of the RIA.

1. Reference Cases

Our primary reference case renewable fuel volumes are based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007 reference case projections.[38] While AEO 2007 is not as up-to-date as AEO 2008 or AEO 2009, we chose to use AEO 2007 because later versions of AEO already include the impact of increased renewable fuel volumes under EISA as well as fuel economy improvements under CAFE as required in EISA, whereas AEO 2007 did not.

For the final rule we have also assessed a number of the impacts relative to a reference case assuming the mandated renewable fuel volumes under RFS1 from the Energy Policy Act of 2005 (EPAct). This allows for a more complete assessment of the impacts of the EISA volume

[38] AEO 2007 was only used to derive renewable fuel volume projections for the primary reference case. AEO 2009 was used for future crude oil cost estimates and for estimating total transportation fuel energy use.

mandates, especially when combined with the impacts assessment conducted for the RFS1 rulemaking (though many factors have changed since then). Table IV.A.1-1 summarizes the 2022 renewable fuel volumes for the AEO 2007 and the RFS1 reference cases (listed in both straight volumes and ethanol-equivalent volumes).

Table IV.A.1-1
Reference Case Renewable Fuel Volumes in 2022 (billion gallons)

	Advanced Biofuel			Non-Advanced Biofuel	Total Renewable Fuel
	Cellulosic Biofuel	Biomass-Based Diesel[a]	Other Advanced Biofuel		
Source/Volume Type	Cellulosic Ethanol[c]	FAME Biodiesel[b]	Imported Ethanol	Corn Ethanol	
AEO 2007 Straight Volume	0.25	0.38	0.64	12.29	13.56
AEO 2007 Ethanol-Equivalent	0.25 0.	58	0.64	12.29	13.76
RFS 1 Straight Volume	0.00 0.	30	0.00 7.	05	7.35
RFS 1 Ethanol-Equivalent	0.00 0.	45	0.00 7.	05	7.50

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.
[b] Only fatty acid methyl ester (FAME) biodiesel volumes were considered
[c] Under the RFS1 reference case, we assumed the 250-million gallon cellulosic standard set by EPAct would be met primarily by corn ethanol plants utilizing 90% biomass for energy, thus actual production of cellulosic biofuel is zero. AEO 2007 reference case assumes actual production of cellulosic biofuel and therefore assumed to be 0.25 billion gallons.

2. Primary Control Case

Our assessment of the renewable fuel volumes required to meet EISA necessitates establishing a primary set of fuel types and volumes on which to base our assessment of the impacts of the new standards. EISA contains four broad categories: cellulosic biofuel, biomass-based diesel, total advanced biofuel, and total renewable fuel. As these categories could be met with a wide variety of fuel choices, in order to assess the impacts of increased volumes of renewable fuel, we projected a set of reasonable renewable fuel volumes based on our projection of fuels that could come to market.

Although actual volumes and feedstocks will be different, we believe the projections made for our control cases are within the range of possible predictions for which the standards are met and allow for an assessment of the potential impacts of increased volumes of renewable fuel. Table IV.A.2-1 summarizes the fuel types used for the primary control case and their corresponding volumes for the year 2022.

Table IV.A.2-1
Primary Control Case Projected Renewable Fuel Volumes in 2022 (billion gallons)

	Advanced Biofuel						Non-Advanced Biofuel	Total Renewable Fuel
	Cellulosic Biofuel		Biomass-Based Diesel[a]		Other Advanced Biofuel			
Volume Type	Cellulosic Ethanol	Cellulosic Diesel[b]	FAME[c] Biodiesel	NCRD[d]	Other Biodiesel[e]	Imported Ethanol	Corn Ethanol	
Straight Volume	4.92	6.52	0.85	0.15	0.82	2.24	15.00	30.50
Ethanol-Equivalent	4.92 11	.08	1.28	0.26	1.23	2.24	15.00	36.00

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.
[b] Cellulosic Diesel includes at least 1.96 billion gallons (3.33 billion ethanol-equivalent gallons) from Fischer-Tropsch Biomass-to-Liquids (BTL) processes based on EIA's forecast and an additional 4.56 billion gallons (7.75 billion ethanol-equivalent gallons) from this or other types of cellulosic diesel processes
[c] Fatty acid methyl ester (FAME) biodiesel
[d] Non-Co-processed Renewable Diesel (NCRD)
[e] Other Biodiesel is biodiesel that could be produced in addition to the amount needed to meet the biomass-based diesel standard.

The following subsections detail our rationale for projecting the amount and type of fuels needed to meet EISA as shown in Table IV.A.2-1. For cellulosic biofuel we have assumed that by 2022 on a straight-volume basis about half would come from cellulosic ethanol and the other half from cellulosic diesel. On an ethanol-equivalent volume basis, cellulosic diesel would make up almost 70% of the 16 billion gallons cellulosic biofuel standard. Biomass-based diesel is assumed to be comprised of a majority of fatty-acid methyl ester (FAME) biodiesel and a smaller portion of non-co-processed renewable diesel. The portion of the advanced biofuel category not met by cellulosic biofuel and biomass-based diesel is assumed to come mainly from imported sugarcane ethanol with a smaller amount from additional biodiesel sources. The total renewable fuel volume not required to be comprised of advanced biofuels is assumed to be met with corn ethanol with small amounts of other grain starches and waste sugars.

The main difference between the volumes used for the NPRM and the volumes used for the FRM is the inclusion of cellulosic diesel for the FRM. The NPRM made the simplifying assumption that the cellulosic biofuel standard would be met entirely with cellulosic ethanol. However, due to growing interest and recent developments in hydrocarbon-based or so-called "drop-in" renewable fuels as well as butanol, and marketplace challenges for consuming high volumes of ethanol, we have included projections of more non-ethanol renewables in our primary control case for the final rule.[39] In the future, this could include various forms of "green hydrocarbons" (i.e., cellulosic gasoline, diesel and jet) and higher alcohols, but for analysis purposes, we have modeled it as cellulosic diesel fuel. We describe these fuels in greater detail in Section IV.B-D. We have also included some algae-derived biofuels in our FRM analyses

[39] Comments received from Advanced Biofuels Association, Testimony on June 9, 2009 suggesting a number of advanced biofuel technologies will be able to produce renewable diesel, jet fuels, gasoline, and gasoline component fuels (e.g. butanol, iso-octane). Similar comments were received from the New York State Department of Environmental Conservation (Docket EPA-HQ-OAR-2005-0161-2143), OPEI and AllSAFE (Docket EPA-HQ-OAR-2005-0161-2241), and the Low Carbon Synthetic Fuels Association (Docket EPA-HQ-OAR-2005-0161-2310).

given the large interest and potential for such fuels. We have continued to assume zero volume for renewable fuels or blendstocks such as biogas, jatropha, palm, imported cellulosic biofuel, and other alcohols or ethers in our control cases. Although we have not included these renewable fuels and blendstocks in our impact analyses, it is important to note that they can still be counted under our program if they meet the lifecycle thresholds and definitions for renewable biomass, and recent information suggests that some of them may be likely.

a. Cellulosic Biofuel

As discussed in our NPRM, whether cellulosic biofuel is ethanol will depend on a number of factors, including production costs, the form of tax subsidies, credit programs, and factors influencing the blending of biofuel into the fuel pool. It will also depend on the relative demand for gasoline and diesel fuel. As a result of our analyses on ethanol consumption (see Section IV.D) and continual tracking of the industry's interest in hydrocarbon-based renewables (see Section IV.B), we have decided to analyze a cellulosic biofuel standard made up of both cellulosic ethanol and cellulosic diesel fuels.

For assessing the impacts of the RFS2 standards, we used AEO 2009 (April release) cellulosic ethanol volumes (4.92 billion gallons), as well as the cellulosic biomass-to-liquids (BTL) diesel volumes (1.96 billion gallons) using Fischer-Tropsch (FT) processes. We consider BTL diesel from FT processes as a subset of cellulosic diesel. In order to reach a total of 16 billion ethanol-equivalent gallons, we assumed that an additional 4.56 billion gallons of cellulosic diesel could be produced from other cellulosic diesel processes. Refer to Section 1.2 of the RIA for more discussion.

b. Biomass-Based Diesel

Biomass-based diesel can include fatty acid methyl ester (FAME) biodiesel, renewable diesel (RD) that has not been co-processed with a petroleum feedstock, as well as cellulosic diesel. Although cellulosic diesel could potentially contribute to the biomass-based diesel category, we have assumed for our analyses that the fuel produced through Fischer-Tropsch (F-T) or other processes and its corresponding feedstocks (cellulosic biomass) are already accounted for in the cellulosic biofuel category discussed previously in Section IV.A.2.a.

FAME and RD processes can both utilize vegetable oils, rendered fats, and greases, and thus will generally compete for the same feedstock pool. We have based RD volumes on our forecast of industry plans, and expect these plants to use rendered fats as feedstock. Most biodiesel plants now have the capability to use vegetable or animal fats as feedstock, and thus our analysis assumes biodiesel will be made from a mix of inputs, depending on local availability, economics, and season. Refer to Section 1.1 of the RIA for more detail on FAME and RD feedstocks

Renewable diesel production can be further classified as co-processed or non-co-processed, depending on whether the renewable material is mixed with petroleum during the hydrotreating operations. EISA specifically forbids co-processed RD from being counted as biomass-based diesel, but it can still count toward the total advanced biofuel requirement. At this time, based on current industry plans, we expect most, if not all, RD will be non-co-processed (that is, non-refinery operations).

Perhaps the feedstock with the greatest potential for providing large volumes of oil for the production of biomass-based diesel is algae. However, several technical hurdles do still exist. Specifically, more efficient harvesting, dewatering, and lipid extraction methods are needed to lower costs to a level competitive with other feedstocks. For all three control cases, we have chosen to include 100 million gallons of algae-based biodiesel by 2022. We believe this is reasonable given several announcements from the algae industry about their production plans.[40] Although algae to biofuel companies can focus on producing algae oil for traditional biodiesel production, several companies are alternatively using algae for producing ethanol or crude oil for gasoline or diesel which could also help contribute to the advanced biofuel mandate. For more detail on algae as a feedstock, refer to Section 1.1 of the RIA.

During the comment period, we received information from stakeholders on alternative biodiesel feedstocks such as camelina and pennycress, to name a few. These feedstocks are currently being researched due to their potential for lower agricultural inputs and higher oil yields than traditional vegetable oil feedstocks as well as their use in additional crop rotations (i.e., winter cover crops) on a given area of land. We acknowledge that as we learn more about the challenges and benefits to the use of newer feedstocks, these could be used in the future towards meeting the biomass-based diesel standard under the RFS2 program provided they meet the lifecycle thresholds and definitions for renewable biomass. For the purpose of our impacts analysis, however, we have chosen not to include these feedstocks in our analyses at this time.

c. Other Advanced Biofuel

As defined in EISA, advanced biofuel includes the cellulosic biofuel and biomass-based diesel categories that were mentioned in Sections IV.A.2.a and IV.A.2.b above. However, EISA requires greater volumes of advanced biofuel than just the volumes required of these fuels. It is entirely possible that greater volumes of cellulosic biofuel and biomass-based diesel than required by EISA could be produced in the future. Our control case assumes that the cellulosic biofuel volumes will not exceed those required under EISA. We do assume, however, that additional biodiesel than that needed to meet the biomass-based diesel volume will be used to meet the total advanced biofuel volume. Despite additional volumes assumed from biodiesel, to fully meet the total advanced biofuel volume required under EISA, other types of advanced biofuel are necessary through 2022.

We have assumed for our control case that the most likely sources of advanced fuel other than cellulosic biofuel and biomass-based diesel would be from imported sugarcane ethanol and perhaps limited amounts of co-processed renewable diesel. Our assessment of international fuel ethanol production and demand indicate that anywhere from 3.8-4.2 Bgal of sugarcane ethanol

[40] Sapphire Energy plans for 135 MMgal by 2018 and 1 Bgal by 2025; Petrosun plans for 30 MMgal/yr facility; Solazyme plans for 100 MMgal by 2012/13; U.S. Biofuels plans for 4 MMgal by 2010 and 50 MMgal by full scale. Only several companies have thus far revealed production plans, and more are announced each day. It is important to realize that future projections are highly uncertain, and we have taken into account the best information we could acquire at the time.

from Brazil could be available for export by 2020/2022. If this volume were to be made available to the U.S., then there would be sufficient volume to meet the advanced biofuel standard. To calculate the amount of imported ethanol needed to meet the EISA advanced biofuel standards, we assumed it would make up the difference not met by cellulosic biofuel, biomass-based diesel and additional biodiesel categories (see Table IV.A.2-1). The amount of imported ethanol required by 2022 is approximately 2.2 Bgal.

As discussed in the NPRM, other potential advanced biofuels could include for example, U.S. domestically produced sugarcane ethanol, biobutanol, and biogas. While we have not chosen to reflect these fuels in our control case, they can still be counted under our program assuming they meet the lifecycle thresholds and other definitions under the program.

d. Other Renewable Fuel

The remaining portion of total renewable fuel not met with advanced biofuel was assumed to come from corn-based ethanol (including small amounts from other grains and waste sugars). EISA effectively sets a limit for participation in the RFS program of 15 Bgal of corn ethanol, and we are assuming for our analysis that sufficient corn ethanol will be produced to meet the 15-Bgal limit that either meets the 20% GHG threshold or is grandfathered. It should be noted, however, that there is no specific "corn-ethanol" mandated volume, and that any advanced biofuel produced above and beyond what is required for the advanced biofuel requirements could reduce the amount of corn ethanol needed to meet the total renewable fuel standard. This occurs in our projections during the earlier years (2010-2015) in which we project that some fuels could compete favorably with corn ethanol (e.g., biodiesel and imported ethanol). Refer to Section 1.2 of the RIA for more details on interim years. Beginning around 2016, fuels qualifying as advanced biofuels likely will be devoted to meeting the increasingly stringent volume mandates for advanced biofuel. It is also important to note that more than 15 Bgal of corn ethanol could be produced and RINs generated for that volume under the RFS2 regulations. However, obligated parties would not be required to purchase more than 15 Bgal worth of non-advanced biofuel RINs, e.g. corn ethanol RINs.

3. Additional Control Cases Considered

Since there is significant uncertainty surrounding what fuels will be produced to meet the 16 billion gallon cellulosic biofuel standard, we have decided to investigate two other sensitivity cases for our cost and emission impact analyses conducted for the rule. The first case, we refer to as the "low-ethanol" control case and assume only 250 million gallons of cellulosic ethanol (from AEO 2007 reference case). The rest of the 16 billion gallon cellulosic biofuel standard is made up of cellulosic diesel as shown in Table IV.A.3-1. The second case, we refer to as the "high-ethanol" control case and assume the entire 16 billion gallon cellulosic biofuel standard is met with cellulosic ethanol, also shown in Table IV.A.3-1.

Table IV.A.3-1
Control Case Projected Renewable Fuel Volumes in 2022 (billion gallons)

	Advanced Biofuel						Non-Advanced Biofuel	Total Renewable Fuel
	Cellulosic Biofuel		Biomass-Based Diesel[a]		Other Advanced Biofuel			
Case/ Volume Type	Cellulosic Ethanol	Cellulosic Diesel[b]	FAME[c] Biodiesel	NCRD[d]	Other Biodiesel[e]	Imported Ethanol	Corn Ethanol	
Low-Ethanol Straight Volume	0.25	9.26	0.85	0.15	0.82	2.24	15.00	28.57
Low-Ethanol Ethanol-Equivalent	0.25	15.75	1.28	0.26	1.23	2.24	15.00	36.00
High-Ethanol Straight Volume	16.00	0.00	0.85	0.15	0.82	2.24	15.00	35.06
High-Ethanol Ethanol-Equivalent	16.00	0.00	1.28	0.26	1.23	2.24	15.00	36.00

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.
[b] Cellulosic Diesel includes 1.96 billion gallons (3.33 ethanol-equivalent billion gallons) from Fischer-Tropsch Biomass-to-Liquids (BTL) processes and 7.30 billion gallons (12.42 ethanol-equivalent billion gallons) from other types of cellulosic diesel processes for the Low-Ethanol case and zero cellulosic diesel in the High-Ethanol Case
[c] Fatty acid methyl ester (FAME) biodiesel
[d] Non-Co-processed Renewable Diesel (NCRD)
[e] Other Biodiesel is biodiesel that could be produced in addition to the amount needed to meet the biomass-based diesel standard.

In comparison, our primary control case described in Section IV.A.2, could be considered a "mid-ethanol" control case, as the cellulosic ethanol and diesel volumes analyzed are in between the low-ethanol and high-ethanol cases described in this section. We believe the addition of these sensitivity cases is useful in understanding the potential impacts of the renewable fuels standards. Refer to Section 1.2 of the RIA for more detail on three control cases analyzed as part of this rule.

B. Renewable Fuel Production

1. Corn/Starch Ethanol

The majority of domestic biofuel production currently comes from plants processing corn and other similarly-processed grains in the Midwest. However, there are a handful of plants located outside the Corn Belt and a few plants processing simple sugars from food or beverage waste. In this section, we summarize the present state of the corn/starch ethanol industry and discuss how we expect things to change in the future under the RFS2 program.

a. Historic/Current Production

The United States is currently the largest ethanol producer in the world. In 2008, the U.S. produced nine billion gallons of fuel ethanol for domestic consumption, the majority of which came from locally-grown corn.[41] The nation is currently on track for producing over 10 billion gallons by the end of 2009.[42] Although the U.S. ethanol industry has been in existence since the 1970s, it has rapidly expanded in recent years due to the phase-out of methyl tertiary butyl ether (MTBE), elevated crude oil prices, state mandates and tax incentives, the introduction of the Federal Volume Ethanol Excise Tax Credit (VEETC)[43], the implementation of the existing RFS1 program[44], and the new volume requirements established under EISA. As shown in Figure IV.B.1-1, U.S. ethanol production has grown exponentially over the past decade.

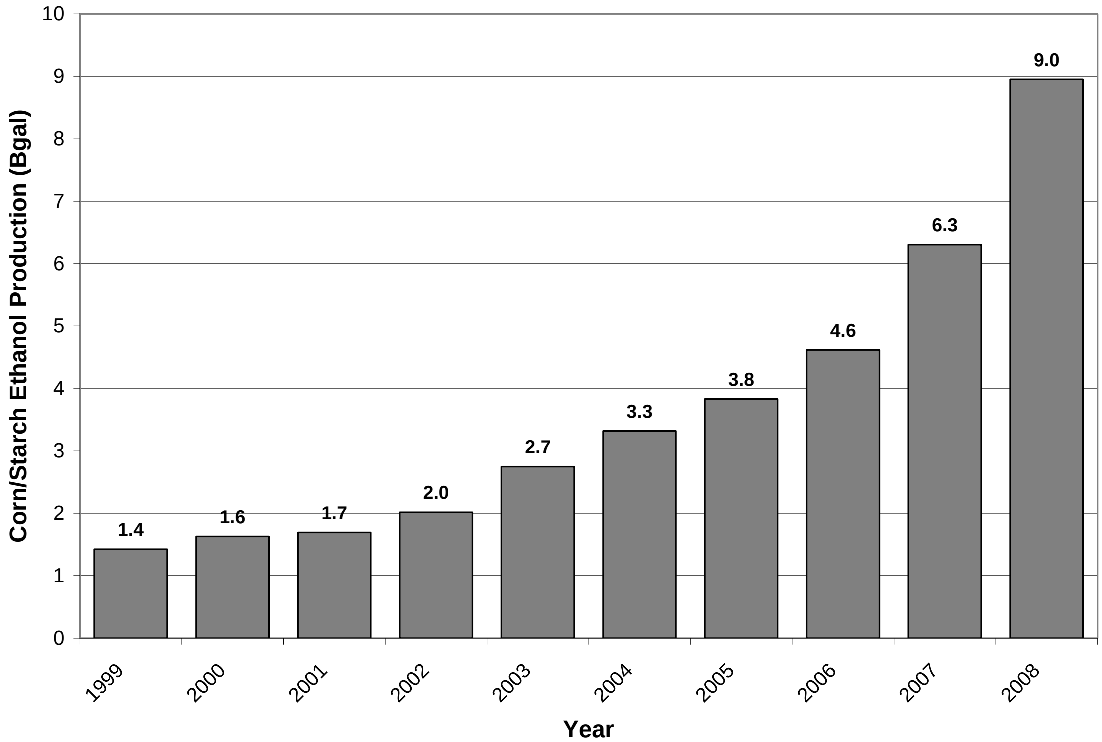
[41] Based on total transportation ethanol reported in EIA's September 2009 Monthly Energy Review (Table 10.2) less imports (http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm).

[42] Based on ethanol projected in EIA's October 2009 Short Term Energy Outlook less projected imports. Actual year-end data for 2009 was unavailable at the time of this FRM assessment.

[43] On October 22, 2004, President Bush signed into law H.R. 4520, the American Jobs Creation Act of 2004 (JOBS Bill), which created the Volumetric Ethanol Excise Tax Credit (VEETC). The $0.51/gal ethanol blender credit replaced the former fuel excise tax exemption, blender's credit, and pure ethanol fuel credit. However, the 2008 Farm Bill modified the alcohol credit so that corn ethanol gets a reduced credit of $0.45/gal and cellulosic biofuel gets a credit of $1.01/gal.

[44] On May 1, 2007, EPA published a final rule (72 FR 23900) implementing the Renewable Fuel Standard required by EPAct (also known as RFS1). RFS1 requires that 4.0 billion gallons of renewable fuel be blended into gasoline/diesel by 2006, growing to 7.5 billion gallons by 2012.

Figure IV.B.1-1
Historical Growth in U.S. Corn/Starch Ethanol Production[45]



[45] Based on total transportation ethanol reported in EIA's September 2009 Monthly Energy Review (Table 10.2) less imports (http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm).

As of November 2009 there were 180 corn/starch ethanol plants operating in the U.S. with a combined production capacity of approximately 12 billion gallons per year.[46] This does not include idled ethanol plants, discussed later in this subsection. The majority of today's ethanol production (91.5% by volume) comes from 155 plants relying exclusively on corn. Another 8.3% comes from 18 plants processing a blend of corn and/or similarly-processed grains (milo, wheat, or barley). The remainder comes from seven small plants processing waste beverages or other waste sugars and starches.

Of the 173 plants processing corn and/or other similarly processed grains, 162 utilize dry-milling technologies and the remaining 11 plants rely on wet-milling processes. Dry mill ethanol plants grind the entire kernel and generally produce only one primary co-product: distillers' grains with solubles (DGS). The co-product is sold wet (WDGS) or dried (DDGS) to the agricultural market as animal feed. However, there are a growing number of plants using front-end fractionation to produce food-grade corn oil or back-end extraction to produce fuel-grade corn oil for the biodiesel industry. A company called GreenShift has corn oil extraction facilities located at five ethanol plants in Michigan, Indiana, New York and Wisconsin.[47] Collectively, these facilities are designed to extract in excess of 7.3 million gallons of corn oil per year. Primafuel Solutions is another company offering corn oil extraction technologies to make existing ethanol plants more sustainable. For more information on corn oil extraction and other advanced technologies being pursued by today's corn ethanol industry, refer to Section 1.4.1 of the RIA.

In contrast to dry mill plants, wet mill facilities separate the kernel prior to processing into its component parts (germ, fiber, protein, and starch) and in turn produce other co-products (usually gluten feed, gluten meal, and food-grade corn oil) in addition to DGS. Wet mill plants are generally more costly to build but are larger in size on average.[48] As such, 11.4% of the current grain ethanol production comes from the 11 previously-mentioned wet mill facilities.

The remaining seven ethanol plants process waste beverages or waste sugars/starches and operate differently than their grain-based counterparts. These small production facilities do not require milling and operate simpler enzymatic fermentation processes.

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[46] Our November 2009 corn/starch ethanol industry characterization was based on a variety of sources including plant lists published online by the Renewable Fuels Association and Ethanol Producer Magazine (updated October 22, 2009), information from ethanol producer websites including press releases, and follow-up correspondence with producers. The baseline does not include ethanol plants whose primary business is industrial or food-grade ethanol production nor does it include plants that might be located in the Virgin Islands or U.S. territories. Where applicable, current/historic production levels have been used in lieu of nameplate capacities to estimate production capacity.

[47] Two plants in Michigan and one in each of the other three states. All company information based on GreenShift's Q2 2009 SEC filing available at http://www.greenshift.com/pdf/GERS_Form10Q_Q209_FINAL.pdf.

[48] According to our November 2009 corn ethanol plant assessment, the average wet mill plant capacity is 125 million gallons per year – almost twice that of the average dry mill plant capacity (65 million gallons per year). For more on average plant sizes, refer to Section 1.5 of the RIA.

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. Steam needed to heat the process is generally produced on-site or by other dedicated boilers.[49] The ethanol industry relies primarily on natural gas. Of today's 180 ethanol production facilities, an estimated 151 burn natural gas[50] (exclusively), three burn a combination of natural gas and biomass, one burns natural gas and coal (although natural gas is the primary fuel), one burns a combination of natural gas, landfill biogas and wood, and two burn natural gas and syrup from the process. We are aware of 17 plants that burn coal as their primary fuel and one that burns a combination of coal and biomass.[51] Our research suggests that three corn ethanol plants rely on a combination of waste heat and natural gas and one plant does not have a boiler and relies solely on waste heat from a nearby power plant. Overall, our research suggests that 27 plants currently utilize cogeneration or combined heat and power (CHP) technology, although others may exist.[52] CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party, CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production.[53]

During the ethanol fermentation process, large amounts of carbon dioxide (CO_2) gas are released. In some plants the CO_2 is vented into the atmosphere, but where local markets exist, it is captured, purified, and sold to the food processing industry for use in carbonated beverages and flash-freezing applications. We are currently aware of 40 fuel ethanol plants that recover CO_2 or have facilities in place to do so. According to Airgas, a leading gas distributor, the U.S. ethanol industry currently recovers 2 to 2.5 million tons of CO_2 per year which translates to about 5-7% of all the CO_2 produced by the industry.[54]

Since the majority of ethanol is made from corn, it is no surprise that most of the plants are located in the Midwest near the Corn Belt. Of today's 180 ethanol production facilities, 163 are located in the 15 states comprising PADD 2. For a map of the government's Petroleum Administration for Defense Districts or PADDs, refer to Figure IV.B.1-2.

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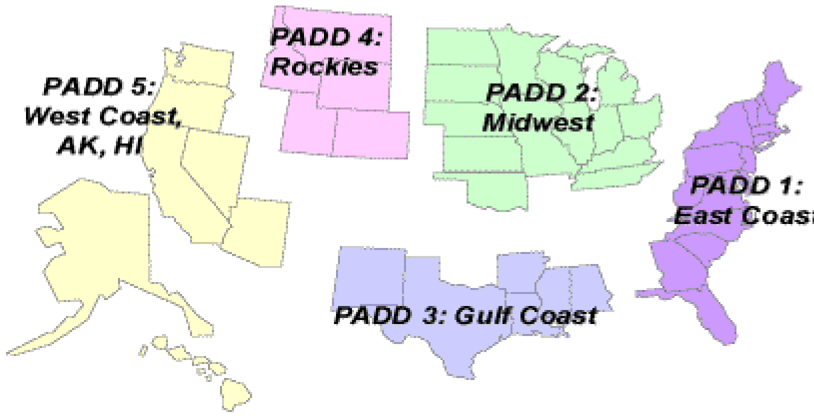
[49] Some plants pull steam directly from a nearby utility.
[50] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.
[51] Includes corrections from NPRM based on new information obtained on Cargill plants and Blue Flint ethanol plant.
[52] CHP assessment based on information provided by EPA's Combined Heat and Power Partnership, literature searches and correspondence with ethanol producers.
[53] For more on CHP technology, refer to Section 1.4.1.3 of the RIA.
[54] Based on information provided by Bruce Woerner at Airgas on August 14, 2009.

Figure IV.B.1-2
Petroleum Administration for Defense Districts



As a region, PADD 2 accounts for over 94% (or 11.3 billion gallons) of today's estimated ethanol production capacity, followed by PADD 3 (2.4%), PADDs 4 and 1 (each with 1.3%) and PADD 5 (0.8%). For more information on today's ethanol plant locations, refer to Section 1.5.1 of the RIA.

The U.S. ethanol industry is currently comprised of a mixture of company-owned plants and locally-owned farmer cooperatives (co-ops). The majority of today's ethanol production facilities are company-owned, and on average these plants are larger in size than farmer-owned co-ops. Accordingly, these facilities account for about 80% of today's online ethanol production capacity.[55] Furthermore, nearly 30% of the total domestic product comes from 40 plants owned by just three different companies – POET Biorefining, Archer Daniels Midland (ADM), and Valero Renewables. Valero entered the ethanol industry in March of 2009 when it acquired seven ethanol plants from former ethanol giant, Verasun. The oil company currently has agreements in place to purchase three more ethanol plants that would bring the company's ethanol production capacity to 1.1 billion gallons per year.[56] However, ethanol plants are much smaller than petroleum refineries. Valero's smallest petroleum refinery in Ardmore, OK has about twice the throughput of all its ethanol plants combined.[57] Still, as obligated parties under RFS1 and RFS2, the refining industry continues to show increased interest in biofuels. Suncor and Murphy Oil recently joined Valero as the second and third oil companies to purchase idled U.S. ethanol plants. Many refiners are also supporting the development of cellulosic biofuels and algae-based biodiesel.

b. Forecasted Production Under RFS2

As highlighted earlier, domestic ethanol production is projected to grow to over 10 billion gallons in 2009. And with over 12 billion gallons of capacity online as of November 2009, ethanol production should continue to grow in 2010, provided plants continue to produce at or above today's production levels. In addition, despite current market conditions (i.e., poor ethanol margins), the ethanol industry is expected to grow in the future under the RFS2 program. Although there is not a set corn ethanol requirement, EISA allows for 15 billion gallons of the 36-billion gallon renewable fuel standard to be met by conventional biofuels. We expect that corn ethanol will fulfill this requirement, provided it is more cost competitive than imported ethanol or cellulosic biofuel in the marketplace.

In addition to the 180 aforementioned corn/starch ethanol plants currently online, 27 plants are presently idled.[58] Some of these are smaller ethanol plants that have been idled for quite some time, whereas others are in a more temporary "hot idle" mode, ready to be restarted. In response to the economic downturn, a number of ethanol producers have idled production,

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[55] Company-owned plants were assumed to be all those companies not denoted as locally-owned based on Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated October 22, 2009). For more on average plant sizes, refer to Section 1.5.1 of the RIA.

[56] Valero recently announced that it has purchase agreements in place to acquire the last two Verasun plants in Linden, IN and Bloomington, OH and the former Renew Energy plant in Jefferson Junction, WI.

[57] Based on refinery information provided at http://www.valero.com/OurBusiness/OurLocations/

[58] Based on our November 2009 corn/starch ethanol industry characterization. We are aware of at least one plant that has come back online since then.

halted construction projects, sold off plants and even filed for Chapter 11 bankruptcy protection. Some corn ethanol companies have exited the industry all together (e.g., Verasun) whereas others are using bankruptcy as a means to protect themselves from creditors as they restructure their finances with the goal of becoming sustainable.

Crude oil prices are expected to increase in the future making corn ethanol more economically viable. According to EIA's AEO 2009, crude oil prices are projected to increase from about $80/barrel (today's price) to $116/barrel by 2022.[59] As oil and gas prices rebound, we expect that the biofuels industry will as well. Since our April 2009 industry assessment used for the NPRM, at least nine corn ethanol plants have come back online.

For analysis purposes, we assumed that all 27 idled corn/starch ethanol plants would resume operations by 2022 under the RFS2 program. We also assumed that a total of 11 new ethanol plants and two expansion projects currently under construction or in advanced stages of planning would come online.[60] This includes two large dry mill expansion projects currently underway at existing ADM wet mill plants and two planned combination corn/cellulosic ethanol plants that received funding from DOE. While several of these projects are delayed or on hold at the moment, we expect that these facilities (or comparable replacement projects) would eventually come online to get the nation to approximately 15 billion gallons of corn ethanol production capacity.

[59] EIA, Annual Energy Outlook 2009 – ARRA Update (Table 12).
[60] Sources include Renewable Fuels Association, Ethanol Biorefinery Locations (updated October 22, 2009) and Ethanol Producer Magazine, Producing, Not Producing, Under Construction, and Expansions lists (last modified on October 22, 2009) in addition to information gathered from producer websites and follow-up correspondence.

Almost 100% of conventional ethanol plant growth is expected to come from facilities processing corn or other similarly processed grains. And not surprisingly, the majority of growth (approximately 70% by volume) is expected to originate from PADD 2. However, growth is expected to occur in all PADDs. With the exception of one facility[61], all new corn/grain ethanol plants are expected to utilize dry milling technologies and the majority of new production is expected to come from plants burning natural gas. However, we anticipate that two manure biogas plants[62], one biomass-fired plant, and two coal-fired ethanol plants will be added to the mix.[63] Of these new and returning idled plants, we're aware of five facilities currently planning to use CHP technology, bringing the U.S. total to 32.

The above predictions are based on the industry's current near-term production plans. However, we anticipate additional growth in advanced ethanol production technologies under the RFS2 program. Forecasted fuel prices are projected to drive corn ethanol producers to transition from conventional boiler fuels to biomass feedstocks. In addition, fossil fuel/electricity prices will likely drive a number of ethanol producers to pursue CHP technology. For more on our projected 2022 utilization of these technologies under the RFS2 program, refer to Section 1.5.1.3 of the RIA.

2. Imported Ethanol

As discussed in the proposal, ethanol imports have traditionally played a relatively small role in the U.S. transportation fuel market due to historically low crude prices and the tariff on imported ethanol. Between years 2000 and 2008, the volume of ethanol imported into the U.S. has ranged from 46-720 million gallons per year. So far this year, from January through November 2009, imported ethanol has only reached 197 million gallons.[64] As the data show, the volume of imported ethanol can fluctuate greatly.

In the past, the majority of volume has originated from countries that are part of the Caribbean Basin Initiative. Direct Brazilian imports have also made up a sizeable portion of total ethanol imported into the U.S. However, recently there have been relatively small amounts of direct imports of ethanol from Brazil.[65] This indicates that current market conditions have made importing Brazilian ethanol directly to the U.S. uneconomical. Part of the reason for this decline in imports is the cessation of the duty drawback that became effective on October 1, 2008, but also changes in world sugar prices.[66]

It is difficult to project the potential volume of future ethanol imports to the U.S based purely on historical data. Rather, it is necessary to assess future import potential by analyzing

[61] Tate and Lyle is currently in the process of building a 115 MGY wet mill corn ethanol plant in Fort Dodge, IA.
[62] One manure biogas plant that is currently idled and another that was under construction but is now on hold.
[63] The two coal fired plants are the aforementioned dry mill expansion projects currently underway at existing ADM sites. These projects commenced construction on or before December 19, 2007 and would therefore should likely be grandfathered under the RFS2 rule. For more on our grandfathering assessment, refer to Section 1.5.1.4 of the RIA.
[64] Official Statistics of the U.S. Department of Commerce, U.S. ITC
[65] Approximately 19,000 gallons directly from Brazil in the month of June 2009 and 4 million gallons from Brazil in the month of November 2009, zero gallons reported from November 2008-May 2009 and July 2009-October 2009.
[66] Lundell, Drake, "Brazilian Ethanol Export Surge to End; U.S. Customs Loophole Closed Oct. 1," Ethanol and Biodiesel News, Issue 45, November 4, 2008.

the major players for foreign ethanol production and consumption. In 2008, the top three fuel ethanol producers were the U.S., Brazil, and the European Union (EU), producing 9.0, 6.5, and 0.7 billion gallons, respectively.[67] Consumption of fuel ethanol is also dominated by the United States and Brazil with approximately 9.6 and 4.9 billion gallons consumed in each country, respectively.[68,69] The EU consumed approximately 0.9 billion gallons of fuel ethanol in 2008.[70]

In our assessment of foreign ethanol production and consumption, we analyzed the following countries or group of countries: Brazil, the EU, Japan, India, and China. Our analyses indicate that Brazil would likely be the only nation able to supply any meaningful amount of ethanol to the U.S. in the future. Depending on whether the mandates and goals of the EU, Japan, India, and China are enacted or met in the future, it is likely that this group of countries would consume any growth in their own production and be net importers of ethanol, thus competing with the U.S. for Brazilian ethanol exports.

Due to uncertainties in the future demand for ethanol domestically and internationally, uncertainties in the actual investments made in the Brazilian ethanol industry, as well as uncertainties in future sugar prices, there appears to be a wide range of Brazilian production and domestic consumption estimates. The most current and complete estimates indicate that total Brazilian ethanol exports will likely reach 3.8-4.2 billion gallons by 2022.[71,72,73] As this volume of ethanol export is available to countries around the world, only a portion of this will be available exclusively to the United States. If the balance of the EISA advanced biofuel requirement not met with cellulosic biofuel and biomass-based diesel were to be met with imported sugarcane ethanol alone, it would require about 2.2 billion gallons (see Table IV.A.2-1), or approximately 55% of total Brazilian ethanol export estimates. This is aggressive, yet within the bounds of reason, therefore, we have made this simplifying assumption for the purposes of further analysis.

Generally speaking, Brazilian ethanol exporters will seek routes to countries with the lowest costs for transportation, taxes, and tariffs. With respect to the U.S., the most likely route is through the Caribbean Basin Initiative (CBI).[74] Brazilian ethanol entering the U.S. through CBI countries is not currently subject to the 54 cent/gal imported ethanol tariff and yet receives the 45 cent/gal ethanol blender credit. In addition to the U.S., other countries also have similar

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[67] Renewable Fuels Association (RFA), "2008 World Fuel Ethanol Production, " http://www.ethanolrfa.org/industry/statistics/#E, March 31, 2009.
[68] Ibid.
[69] UNICA, "Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity" Brochure, 2008.
[70] EurObserv'ER, "Biofuels Barometer" July 2009, http://www.eurobserv-er.org/pdf/baro192.pdf.
[71] EPE, "Plano Nacional de Energia 2030," Presentation from Mauricio Tolmasquim, 2007.
[72] UNICA, "Sugarcane Industry in Brazil: Ethanol, Sugar, Bioelectricity," 2008.
[73] USEPA International Visitors Program Meeting October 30, 2007, correspondence with Mr. Rodrigues Technical Director from UNICA Sao Paulo Sugarcane Agro-industry Union, stated approximately 3.7 billion gallons probable by 2017/2020; Consistent with brochure "Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity" from UNICA (3.25 Bgal export in 2015 and 4.15 Bgal export in 2020)
[74] Other preferential trade agreements include the North American Free Trade Agreement (NAFTA) which permits tariff-free ethanol imports from Canada and Mexico and the Andean Trade Promotion and Drug Eradication Act (ATPDEA) which allows the countries of Columbia, Ecuador, Bolivia, and Peru to import ethanol duty-free. Currently, these countries export or produce relatively small amounts of ethanol, and thus we have not assumed that the U.S. will receive any substantial amounts from these countries in the future for our analyses.

tariffs on imported ethanol. Refer to Section 1.5.2 of the RIA for more details. Due to the economic incentive of transporting ethanol through the CBI, we expect the majority of the tariff rate quota (TRQ) to be met or exceeded, perhaps 90% or more. The TRQ is set each year as 7% of the total domestic ethanol consumed in the prior year. If we assume that 90% of the TRQ is met and that total domestic ethanol (corn and cellulosic ethanol) consumed in 2021 was 19.2 Bgal (under the primary control case), then approximately 1.21 Bgal of ethanol could enter the U.S. through CBI countries in 2022. The rest of the Brazilian ethanol exports not entering the CBI will compete on the open market with the rest of the world demanding some portion of direct Brazilian ethanol. To meet our advanced biofuel standard, we assumed 1.03 Bgal of sugarcane ethanol would be imported directly to the U.S. in 2022.

3. Cellulosic Biofuel

The majority of the biofuel currently produced in the United States comes from plants processing first-generation feedstocks like corn, plant oils, sugarcane, etc. Non-edible cellulosic feedstocks have the potential to greatly expand biofuel production, both volumetrically and geographically. Research and development on cellulosic biofuel technologies has exploded over the last few years, and plants to commercialize a number of these technologies are already beginning to materialize. The $1.01/gallon tax credit for cellulosic biofuel that was introduced in the 2008 Farm Bill and recently became effective, is also offering much incentive to this developing industry. In addition to today's RFS2 program which sets aggressive goals for cellulosic biofuel production, the Department of Energy (DOE), Department of Agriculture (USDA), Department of Defense (DOD) and state agencies are helping to spur industry growth.

a. Current State of the Industry

There are a growing number of biofuel producers, biotechnology companies, universities and research institutes, start-up companies as well as refiners investigating cellulosic biofuel production. The industry is currently pursuing a wide range of feedstocks, conversion technologies and fuels. There is much optimism surrounding the long-term viability of cellulosic ethanol and other alcohols for gasoline blending. There is also great promise and growing interest in synthetic hydrocarbons like gasoline, diesel and jet fuel as "drop in" petroleum replacements. Some companies intend to start by processing corn or sugarcane and then transition to cellulosic feedstocks while others are focusing entirely on cellulosic materials. Regardless, cellulosic biofuel production is beginning to materialize.

We are currently aware of over 35 small pilot- and demonstration-level plants operating in North America. However, the main focus at these facilities is research and development, not commercial production. Most of the plants are rated at less than 250,000 gallons per year and that's if they were operated at capacity. Most only operate intermittently for the purpose of demonstrating that the technologies can be used to produce transportation fuels. The industry as a whole is still working to increase efficiency, improve yields, reduce costs and prove to the public, as well as investors, that cellulosic biofuel is both technologically and economically feasible.

As mentioned above, a variety of feedstocks are being investigated for cellulosic biofuel production. There is a great deal of interest in urban waste (MSW and C&D debris) because it is virtually free and abundant in many parts of the country, including large metropolitan areas where the bulk of fuel is consumed. There is also a lot of interest in agricultural residues (corn stover, rice and other cereal straws) and wood (forest thinnings, wood chips, pulp and paper mill waste and yard waste). However, researchers are still working to find viable harvesting and storage solutions. Others are investigating the possibility of growing dedicated energy crops for cellulosic biofuel production, e.g., switchgrass, energy cane, sorghum, poplar, miscanthus and other fast-growing trees. While these crops have tremendous potential, many are starting with the feedstocks that are available today with the mentality that once the industry has proven itself, it will be easier to secure growing contracts and start producing energy crops. For more information on cellulosic feedstock availability, refer to preamble Section IV.B.3.d and Section 1.1.2 of the RIA.

The industry is also pursuing a number of different cellulosic conversion technologies and biofuels. Most of the technologies fall into one of two categories: biochemical or thermochemical. Biochemical conversion involves the use of acids and/or enzymes to hydrolyze cellulosic materials into fermentable sugars and lignin. Thermochemical conversion involves the use of heat to convert biomass into synthesis gas or pyrolysis oil for upgrading. A third technology pathway is emerging that involves the use of catalysts to depolymerize or reform the feedstocks into fuel. The technologies currently being considered are capable of producing cellulosic alcohols or hydrocarbons for the transportation fuel market. Many companies are also researching the potential of co-firing biomass to produce plant energy in addition to biofuels. For a more in-depth discussion on cellulosic technologies, refer to Section 1.4.3 of the RIA.

b. Setting the 2010 Cellulosic Biofuel Standard

The Energy Independence and Security Act (EISA) set aggressive cellulosic biofuel targets beginning with 100 million gallons in 2010. However, EISA also supplied EPA with cellulosic biofuel waiver authority. For any calendar year in which the projected cellulosic biofuel production is less than the minimum applicable volume, EPA can reduce the standard based on the volume expected to be available that year. EPA is required to set the annual cellulosic standard by November 30th each year and should consider the annual estimate made by EIA by October 31st of each year. We are setting the 2010 standard as part of this final rule.

Setting the cellulosic biofuel standard for 2010 represents a unique challenge. As discussed above, the industry is currently characterized by a wide range of companies mostly focused on research, development, demonstration, and financing their developing technologies. In addition, while we are finalizing a requirement that producers and importers of renewable fuel provide us with production outlook reports detailing future supply estimates (refer to §80.1449), we do not have the benefit of this valuable cellulosic supply information for setting the 2010 standard. Finally, since today's cellulosic biofuel production potential is relatively small, and the number of potential producers few (as described in more detail below), the overall volume for 2010 can be heavily influenced by new developments, either positive or negative associated with even a single company, which can be very difficult to predict. This is evidenced by the magnitude of changes in cellulosic biofuel projections and the potential suppliers of these fuels since the proposal.

In the proposal, we did a preliminary assessment of the cellulosic biofuel industry to arrive at the conclusion that it was possible to uphold the 100 million gallon standard in 2010 based on anticipated production. At the time of our April 2009 NPRM assessment, we were aware of a handful of small pilot and demonstration plants that could help meet the 2010 standard, but the largest volume contributions were expected to come from Cello Energy and Range Fuels.

Cello Energy had just started up a 20 million gallon per year (MGY) cellulosic diesel plant in Bay Minette, AL. EPA staff visited the facility twice in 2009 to confirm that the first-of-its-kind commercial plant was mechanically complete and poised to produce cellulosic biofuel. It was assumed that start-up operations would go as planned and that the facility would be operating at full capacity by the end of 2009 and that three more 50 MGY cellulosic diesel plants planned for the Southeast could be brought online by the end of 2010.

At the time of our assessment, we were also anticipating cellulosic biofuel production from Range Fuels' first commercial-scale plant in Soperton, GA. The company received a $76 million grant from DOE to help build a 40 MGY wood-based ethanol plant and they broke ground in November 2007. In January 2009, Range was awarded an $80 million loan guarantee from USDA.[75] With the addition of this latest capital, the company seemed well on its way to completing construction of its first 10 MGY phase by the end of 2009 and beginning production in 2010.

Since our April 2009 industry assessment there have been a number of changes and delays in production plans due to technological, contractual, financial and other reasons. Cello

[75] For more information on federal support for biofuels, refer to Section 1.5.3.3 of the RIA.

Energy and Range Fuels have delayed or reduced their production plans for 2010. Some of the small plants expected to come online in 2010 have pushed back production to the 2011-2012 timeframe, e.g., Clearfuels Technology, Fulcrum River Biofuels, and ZeaChem. Alltech/Ecofin and RSE Pulp & Chemical, two companies that were awarded DOE funding back in 2008 to build small-scale biorefineries appear to be permanently on hold or off the table. In addition, Bell Bio-Energy, a company that received DOD funding has since abandoned plans to produce cellulosic diesel from MSW at U.S. military bases.[76]

At the same time, there has also been an explosion of new companies, new business relationships, and new advances in the cellulosic biofuel industry. Keeping track of all of them is a challenge in and of it self as the situation can change on a daily basis. EIA recently provided EPA with their first cellulosic biofuel supply estimate required under CAA section 211(o)(7)(D)(i). In a letter to the Administrator dated October 29, 2009, they arrived at a 5.04 million gallon estimate for 2010 based on publicly available information and assumptions made with respect production capacity utilization.[77] A summary of the plants they considered is shown below in Table IV.B.3-1.

Table IV.B.3-1
EIA's Projected Cellulosic Biofuel Plant Production Capacities for 2010

Online	Company	Location	Product	Capacity (million gallons)	Expected Utilization (%)	Production (million gallons)[3]
2007	KL Process Design	Upton, WY	Ethanol	1.5	10	0.15
2008	Verenium	Jennings, LA	Ethanol	1.4	10	0.14
2008	Terrabon	Bryan, TX	Bio-Crude	0.93	10	0.09
2010	Zeachem	Boardman, OR	Ethanol	1.5	10	0.15
2010	Cello Energy	Bay Minette, AL	Diesel	20.0	10[1]	2.00
2010	Range Fuels	Soperton, GA	Ethanol	5.0[2]	50	2.5
Total				30.35		5.04

Notes: 1. Cello Energy is assigned a 10-percent utilization factor as they have not been able to run on a continuous basis long enough to apply for a Synthetic Minor Operating Permit or produce significant amounts of fuel during 2009. 2. It is estimated that only half the 2010 projected capacity (10 million gallons per year) will be a qualified fuel. 3. The production from these facilities in 2009 is not surveyed by EIA or EPA.

In addition to receiving EIA's information and coordinating with them and other offices in DOE, we have initiated meetings and conversations with over 30 up-and-coming advanced biofuel companies to verify publicly available information, obtain confidential business information, and better assess the near-term cellulosic biofuel production potential for use in setting the 2010 standard. What we have found is that the cellulosic biofuel landscape has continued to evolve. Based on information obtained, not only do we project significantly different production volumes on a company-by-company basis, but the list of potential producers of cellulosic biofuel in 2010 is also significantly different than that identified by EIA.

[76] Bell Bio-Energy is currently investigating other locations for turning MSW into diesel fuel according to an October 14, 2009 conversation with JC Bell.
[77] Letter from Richard Newell, EIA Administrator to Lisa Jackson, EPA Administrator dated October 29, 2009 (Table 2).

Overall, our industry assessment suggests that it is difficult to rely on commercial production from small pilot or demonstration-level plants. The primary purpose of these facilities is to prove that a technology works and demonstrate to investors that the process is capable of being scaled up to support a larger commercial plant. Small plants are cheaper to build to demonstrate technology than larger plants, but the operating costs ($/gal) are higher due to their small scale. As a result, it's not economical for most of these facilities to operate continuously. Most of these plants are regularly shut down and restarted as needed as part of the research and development process. Due to their intermittent nature, most of these plants operate at a fraction of their rated capacity, some less than the 10% utilization rate assumed by EIA. In addition, few companies plan on making their biofuel available for commercial sale.

However, there are at least two cellulosic biofuel companies currently operating demonstration plants in the U.S. and Canada that could produce fuel commercially in 2010. The first is KL Energy Corporation, a company we considered for the NPRM with a 1.5 MGY cellulosic ethanol plant in Upton, WY. This plant was considered by EIA and is included in Table IV.B.3-1. The second is Iogen's cellulosic ethanol plant in Ottawa, Canada with a 0.5 MGY capacity. Iogen's commercial demonstration plant was referenced by EIA as a potential foreign source for cellulosic biofuel but was not included in their final table. In addition to these online demonstration plants, there are three additional companies not on EIA's list that are currently building demonstration-level cellulosic biofuel plants in North America that are scheduled to come online in 2010. This includes DuPont Danisco Cellulosic Ethanol and Fiberight, companies building demonstration plants in the U.S. and Enerkem, a company building a demonstration plant in Canada. Cello Energy's plant in Bay Minette, AL continues to offer additional potential for cellulosic biofuel in 2010. And finally, Dynamotive, a company that currently has two biomass-based pyrolysis oil production plants in Canada is another potential source of cellulosic biofuel in 2010. All seven aforementioned companies are discussed in greater detail below along with Range Fuels.

KL Energy Corporation (KL Energy), through its majority-owned Western Biomass Energy, LLC (WBE) located in Upton, WY, is designed to convert wood products and wood waste products into ethanol. Since the end of construction in September 2007, equipment commissioning and process revisions continued until the October 2009 startup. The plant was built as a 1.5 MGY demonstration plant and was designed to both facilitate research and operate commercially. It is KL Energy's intent that WBE's future use will involve the production and sale of small but commercial-quality volumes of ethanol and lignin co-product. The company's current 2010 goal is for WBE to generate RINs under the RFS2 program.[78]

Iogen is responsible for opening the first commercial demonstration cellulosic ethanol plant in North America. Iogen's plant located in Ottawa, Canada has been producing cellulosic ethanol from wheat straw since 2004. Like KL Energy, Iogen has slowly been ramping up production at its 0.5 MGY plant. According to the company's website, they produced approximately 24,000 gallons in 2004 and 34,000 gallons in 2005. Production dropped dramatically in 2006 and 2007 but came back strong with 55,000 gallons in 2008. Iogen recently

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[78] Based on information provided by Lori Litzen, Environmental Permit Engineer at KL Energy on December 10, 2009.

produced over 150,000 gallons of ethanol from the demonstration plant in 2009. Iogen also recently became the first cellulosic ethanol producer to sell its advanced biofuel at a retail service station in Canada. Their cellulosic ethanol was blended to make E10 available for sale to consumers at an Ottawa Shell station. Iogen also recently announced plans to build its first commercial scale plant in Prince Albert, Saskatchewan in the 2011/2012 timeframe. Based on the company's location and operating status, Iogen certainly has the potential to participate in the RFS2 program. However, at this time, we are not expecting them to import any cellulosic ethanol into the U.S. in 2010.[79]

DuPont Danisco Cellulosic Ethanol, LLC (DDCE), a joint venture between DuPont and Danisco, is another potential source for cellulosic biofuel in 2010. DDCE received funding from the State of Tennessee and the University of Tennessee to build a small 0.25 MGY demonstration plant in Vonore, TN to pursue switchgrass-to-ethanol production. According to DDCE, construction commenced in October 2008 and the plant is now mechanically complete and undergoing start-up operations. The facility is scheduled to come online by the end of January and the company hopes to operate at or around 50% of production capacity in 2010. According to the DDCE, the objective in Vonore is to validate processes and data for commercial scale-up, not to make profits. However, the company does plan to sell the cellulosic ethanol it produces.[80]

Enerkem is another company pursuing cellulosic ethanol production. The Canadian-based company was recently announced as a recipient of a joint $50 million grant from DOE and USDA to build a 10 MGY woody biomass-to-ethanol plant in Pontotoc, MS.[81] The U.S. plant is not scheduled to come online until 2012, but Enerkem is currently building a 1.3 MGY demonstration plant in Westbury, Quebec. According to the company, plant construction in Westbury started in October 2007 and the facility is currently scheduled to come online around the middle of 2010. While it's unclear at this time whether the cellulosic ethanol produced will be exported to the United States, Enerkem has expressed interest in selling its fuel commercially.[82]

Additional cellulosic biofuel could come from Fiberight, LLC (Fiberight) in 2010. We recently became aware of this start-up company and contacted them to learn more about their process and cellulosic biofuel production plans. According to Fiberight, they have been operating a pilot-scale facility in Lawrenceville, VA for three years. They have developed a proprietary process that not only fractionates MSW but biologically converts the non-recyclable portion into cellulosic ethanol and biochemicals. Fiberight recently purchased a shut down corn ethanol plant in Blairstown, IA and plans to convert it to become MSW-to-ethanol capable. According to the company, construction is currently underway and the goal is to bring the 2 MGY demonstration plant online by February or March, 2010. If the plant starts up according to

[79] Based on website information, comments submitted in response to our proposal, and a follow-up phone call with Iogen Executive VP, Jeff Passmore on December 17, 2009.
[80] Based on a December 16, 2009 telephone conversation with DDCE Director of Corporate Communications, Jennifer Hutchins and follow-up e-mail correspondence.
[81] Refer to December 4, 2009 DOE press release entitled, "Recovery Act Announcement: Secretaries Chu and Vilsack Announce More Than $600 Million Investment in Advanced Biorefinery Projects.
[82] Based on an October 14, 2009 meeting with Enerkem and follow-up telephone conversation with VP of Government Affairs, Marie-Helene Labrie on December 14, 2009.

plan, the company intends on making cellulosic ethanol commercially available in 2010 and generating RINS under the RFS2 program. Fiberight's long-term goal is to expand the Blairstown plant to a 5-8 MGY capacity and build other small commercial plants around the country that could convert MSW into fuel.[83]

Cello Energy, a company considered in the proposal, continues to be another viable source for cellulosic biofuel in 2010. Despite recent legal issues which have constrained the company's capital, Cello Energy is still pursuing cellulosic diesel production. According to the company, they are currently working to resolve materials handling and processing issues that surfaced when they attempted to scale up production to 20 MGY from a previously operated demonstration plant. As of November 2009, they were waiting for new equipment to be ordered and installed which they hoped would allow for operations to be restarted as early as February or March, 2010. Cello's other planned commercial facilities are currently on hold until the Bay Minette plant is operational.[84]

Another potential supplier of cellulosic biofuel is Dynamotive Energy Systems (Dynamotive) headquartered in Vancouver, Canada. Dynamotive currently has two plants in West Lorne and Guelph, Ontario that produce biomass-based pyrolysis oil (also known as "BioOil") for industrial applications. The BioOil production capacity between the two plants is estimated at around 9 MGY, but both plants are currently operating at a fraction of their rated capacity.[85] However, according to a recent press release, Dynamotive has contracts in place to supply a U.S.-based client with at least nine shipments of BioOil in 2010. If Dynamotive's BioOil is used as heating oil or upgraded to transportation fuel, it could potentially count towards meeting the cellulosic biofuel standard in 2010.

As for the Range Fuels plant, construction of phase one in Soperton, GA is about 85% complete, with start-up planned for mid-2010. However, there have been some changes to the scope of the project that will limit the amount of cellulosic biofuel that can be produced in 2010. The initial capacity has been reduced from 10 to 4 million gallons per year. In addition, since they plan to start up the plant using a methanol catalyst they are not expected to produce qualifying renewable fuel in 2010. During phase two of their project, currently slated for mid-2012, Range plans to expand production at the Soperton plant and transition from a methanol to a mixed alcohol catalyst. This will allow for a greater alcohol production potential as well as a greater cellulosic biofuel production potential.[86]

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[83] Based on a December 15, 2009 telephone conversation with Fiberight CEO, Craig Stuart-Paul and follow-up e-mail correspondence.
[84] Based on a November 9, 2009 telephone conversation with Cello Energy CEO, Jack Boykin.
[85] According to Dynamotive's website, the Guelph plant has a capacity to convert 200 tonnes of biomass into BioOil per day. If all modules are fully operational, the plant has the ability to process 66,000 dry tons of biomass per year with an energy output equivalent to 130,000 barrels of oil. The West Lorne plant has a capacity to convert 130 tonnes of biomass into BioOil per day which, if proportional to the Guelph plant, translates to an energy-equivalent of 84,500 barrels of oil. According to a November 3, 2009 press release, Dynamotive has contracts in place to supply a U.S.-based client with at least nine shipments of BioOil in 2010.
[86] Based on a November 5, 2009 telephone conversation with Range Fuels VP of Government Affairs, Bill Schafer.

Overall, our most recent industry assessment suggests that there could potentially be over 30 MGY of cellulosic biofuel production capacity online by the end of 2010.[87] However, since most of the plants are still under construction today, the amount of cellulosic biofuel produced in 2010 will be contingent upon when and if these plants come online and whether the projects get delayed due to funding or other reasons. In addition, based on our discussions with the developing industry, it is clear that we cannot count on demonstration plants to produce at or near capacity in 2010, or in their first few years of operation for that matter. The amount of cellulosic biofuel actually realized will depend on whether the process works, the efficiency of the process, and how regularly the plant is run. As mentioned earlier, most small plants, including commercial demonstration plants, are not operated continuously. As such, we cannot base the standard on these plants running at capacity - at least until the industry develops further and proves that such rates are achievable. We currently estimate that production from first-of-it's kind plants could be somewhere in the 25-50% range in 2010. Together, the implementation timelines and anticipated production levels of the plants described above brings the cellulosic biofuel supply estimate to somewhere in the 6-13 million gallon range for 2010.

In addition, it is unclear how much was can rely on Canadian plants for cellulosic biofuel in 2010. Although we currently receive some conventional biofuel imports from Canada and many of the aforementioned Canadian companies have U.S. markets in mind, the country also has its own renewable fuel initiatives that could keep much of the cellulosic biofuel produced from coming to the United States, e.g., Iogen. Finally, it's unclear whether all fuel produced by these facilities will qualify as cellulosic biofuel under the RFS2 program. Several of the companies are producing fuels or using feedstocks which may not in fact qualify as cellulosic biofuel once we receive their detailed registration information. Factoring in these considerations, the cellulosic biofuel potential from the six more likely companies described above could result in several different production scenarios in the neighborhood of the recent EIA estimate. We believe this estimate of 5 million gallons or 6.5 ethanol-equivalent million gallons represents a reasonable yet achievable level for the cellulosic biofuel standard in 2010 considering the degree of uncertainty involved with setting the standard for the first year. As mentioned earlier, we believe standard setting will be easier in future years once the industry matures, we start receiving production outlook reports and there is less uncertainty regarding feasibility of cellulosic biofuel production.

c. Current Production Outlook for 2011 and Beyond

Since the proposal, we have also learned about a number of other cellulosic biofuel projects in addition to those described above. This includes commercial U.S. production plans by Coskata, Enerkem and Vercipia. However, production isn't slated to begin until 2011 or later and the same is true for most of the other larger plants we're aware of that are currently under development. Nonetheless, while cellulosic biofuel production in 2010 may be limited, it is remarkable how much progress the industry has made in such a short time, and there is a tremendous growth opportunity for cellulosic biofuels over the next several years.

Most of the cellulosic biofuel companies we've talked to are in different stages of proving their technologies. Regardless of where they are at, many have fallen behind their

[87] For more information, refer to Section 1.5.3.2 of the RIA.

original commercialization schedules. As with any new technology, there have been delays associated with scaling up capacity, i.e., bugs to work out going from pilot to demonstration to commercialization. However, most are saying it's not the technologies that are delaying commercialization, it is lack of available funding. Obtaining capital has been very challenging given the current recession and the banking sector's financial difficulties. This is especially true for start-up companies that do not have access to capital through existing investors, plant profits, etc. From what we understand, banks are looking for cellulosic companies to be able to show that their plants are easily "scalable" or expandable to commercial size. Many are only considering companies that have built plants to one-tenth of commercial scale and have logged many hours of continuous operation.

The government is currently trying to help in this area. To date, the Department of Energy (DOE) and the Department of Agriculture (USDA) have allocated over $720 million in federal funding to help build pilot and demonstration-scale biorefineries employing advanced technologies in the United States. The largest installment from Recovery Act funding was recently announced on December 4, 2009 and includes funding for a series of larger commercial demonstration plants including cellulosic ethanol projects by Enerkem and INEOS New Planet BioEnergy, LLC. DOE has also issued grants to help fund some of the first commercial cellulosic biofuel plants. Current recipients include Abengoa Bioenergy, BlueFire Ethanol[88] and POET Biorefining in addition to Range Fuels. DOE and USDA are also issuing loan guarantees to help support the up-and-coming cellulosic biofuels industry and funding research and development. Many states are also providing assistance. For more information on government support for biofuels, refer to Section 1.5.3.3 of the RIA.

The refining industry is also helping to fund cellulosic biofuel R&D efforts and some of the first commercial plants. Many of the major oil companies have invested in advanced second-generation biofuels over the past 12-18 months. A few refiners (e.g., BP and Shell) have even entered into joint ventures to become cellulosic biofuel producers. General Motors and other vehicle/engine manufacturers are also providing financial support to help with research and development.

A summary of some of the cellulosic biofuel companies with near-term commercialization plans in North America is provided in Table IV.B.3-2. The capacities presented represent maximum annual average throughput based on each company's current production plans. However, as noted, capacity does not necessarily translate to production. Actual production of cellulosic biofuel will likely be well below capacity, especially in the early years of production. We will continue to track these companies and the cellulosic biofuel industry as a whole throughout the duration of the RFS2 program. In addition, we will continue to collaborate with EIA in annual standard setting. A more detailed discussion of the plants corresponding to these company estimates is provided in Section 1.5.3 of the RIA.

[88] Although BlueFire is still working on obtaining financing to build its first demonstration plant, it has received two installments of federal funding towards its first planned commercial-scale plant. The 19 MGY plant planned for Fulton, MS (originally planned for Southern California) was awarded $40 million from DOE on February 28, 2008 and another $81.1 million from DOE and USDA on December 4, 2009.

Table IV.B.3-2
Potential Growth in Cellulosic Biofuel Capacity by Company and Year*

Cellulosic Company	Biofuel(s)	Capacity Expansion Plans (MGY)					
		Today	Dec-10	Dec-11	Dec-12	Dec-13	2014+
Abengoa	Ethanol	0.02	0.02	0.02	16.02	16.02	16.02
AE Biofuels	Ethanol	0.15	0.15	15.15	20.15	20.15	20.15
BlueFire Ethanol	Ethanol	-	-	-	-	-	22.90
Cello Energy	Diesel	-	20.00	20.00	20.00	20.00	120.00
CMEC / SunOpta	Ethanol	-	-	-	-	-	10.00
Coskata	Ethanol	0.04	0.04	0.04	50.04	50.04	100.04
Dynamotive[a]	BioOil	9.00	9.00	9.00	9.00	9.00	9.00
Enerkem	Ethanol	-	1.30	11.30	21.30	21.30	41.30
Fiberight	Ethanol	-	2.00	6.50	6.50	6.50	6.50
Flambeau River Biofuels	Diesel	-	-	-	8.00	8.00	8.00
Fulcrum Bioenergy	Ethanol	-	-	-	10.50	10.50	10.50
Inbicon / Great River Energy	Ethanol	-	-	-	-	20.00	20.00
INEOS Bio / New Planet Energy	Ethanol	-	-	8.00	8.00	8.00	8.00
Iogen	Ethanol	0.50	0.50	0.50	23.50	23.50	23.50
KL Energy	Ethanol	1.50	1.50	1.50	1.50	1.50	6.50
Mascoma Corporation	Ethanol	0.20	0.20	0.20	2.20	20.20	80.20
New Page	Diesel	-	-	-	2.50	2.50	2.50
Ohio River Clean Fuels / Baardb	Diesel, Naphtha	-	-	-	-	-	17.00
Pacific Ethanol	Ethanol	-	-	-	-	-	2.70
POET Biorefining	Ethanol	0.02	0.02	25.02	25.02	25.02	25.02
Range Fuels	Methanol, Ethanol	-	4.00	4.00	30.00	30.00	100.00
Rentech[c]	Diesel	-	-	0.15	7.15	7.15	7.15
Vercipia (Verenium/BP JV)	Ethanol	1.40	1.40	1.40	37.40	37.40	37.40
Maximum Plant Capacity (MGY)		**12.83**	**40.13**	**102.78**	**298.78**	**336.78**	**694.38**

[a]Capacity has been estimated.

[b]Plant will co-process biomass and coal. It is unclear at this time how much fuel would come from biomass and potentially qualify as cellulosic biofuel.

[c]Includes Clearfuels demo plant and Silvagas commercial plant.

*Capacity, not actual production

d. Feedstock Availability

A wide variety of feedstocks can be used for cellulosic biofuel production, including: agricultural residues, forestry biomass, certain renewable portions of municipal solid waste and construction and demolition waste (i.e., separated food, yard and incidental, and post-recycled paper and wood waste as discussed in Section II.B.4) and energy crops. These feedstocks are currently much more difficult to convert into biofuel than traditional corn/starch crops or at least require new and different processes because of the more complex structure of cellulosic material.

To determine the likely cellulosic feedstocks for production of 16 billion gallons cellulosic biofuel by 2022, we analyzed the data and results from various sources. Sources include agricultural modeling from the Forestry Agriculture Sector Optimization Model (FASOM) to determine the most economical volume of agriculture residues, energy crops, and forestry resources (see Section VIII for more details on the FASOM) used to meet the standard. We supplemented these estimates with feedstock assessment estimates for the biomass portions of municipal solid waste and construction and demolition waste.[89]

The following subsections describe the availability of various cellulosic feedstocks and the estimated amounts from each feedstock needed to meet the EISA requirement of 16 Bgal of cellulosic biofuel by 2022. Refer to Section IV.B.2.c.iv for the summarized results of the types and volumes of cellulosic feedstocks chosen based on our analyses.

i. *Urban Waste*

Cellulosic feedstocks available at the lowest cost to the ethanol producer will likely be chosen first. This suggests that urban waste which is already being gathered today and incurs a fee for its disposal may be among the first to be used. Urban wastes are used in a variety of ways. Most commonly, wastes are ground into mulch, dumped into land-fills, or incinerated. We describe two components of urban waste, municipal solid waste (MSW) and construction and demolition (C&D) debris, below.

MSW consists of paper, glass, metals, plastics, wood, yard trimmings, food scraps, rubber, leather, textiles, etc. The portion of MSW that can qualify as renewable biomass under the program is discussed in Section II.B.4.d. The bulk of the biogenic portion of MSW that can be converted into biofuel is cellulosic material such as wood, yard trimmings, paper, and much of food wastes. Paper made up approximately 31% of the total MSW generated in 2008.[90] Although recycling/recovery rates are increasing over time, there appears to still be a large fraction of biogenic material that ends up unused and in land-fills. C&D debris is typically not

[89] It is important to note that our original plant siting analysis for cellulosic ethanol facilities used the most current version of outputs from FASOM at the time, which was from April 2008. The siting analysis was used to inform the air quality modeling, which requires long leadtimes. Since then, FASOM has been updated to reflect better assumptions. Therefore, the version used for the FRM in Section VIII on economic impacts is different from the one used for the plant siting analysis in the NPRM. We do not believe that the differences between the two versions are enough to have a major impact on the plant siting analysis.

[90] EPA. Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and figures for 2008.

available in wood waste assessments, although some have estimated this feedstock based on population. Utilization of such feedstocks could help generate energy or biofuels for transportation. However, despite various assessments on urban waste resources, there is still a general lack of reliable data on delivered prices, issues of quality (potential for contamination), and lack of understanding of potential competition with other alternative uses (e.g., recycling, burning for electricity).

We estimated that a total of 44.5 million dry tons of MSW (wood, yard trimmings, paper, and food waste) and C&D wood waste could be available for producing biofuels after factoring in several assumptions, e.g., percent contamination, percent recovered or combusted for other uses, and percent moisture.[91,92] Between the proposal and this final rule, we have updated the assumptions noted above based on newer reports. It should be noted, however, that our estimates of urban waste availability have not changed significantly between the proposal and the final rule. We assumed that approximately 26 million dry tons (of the total 44.5 million dry tons) could be used to produce biofuels. However, many areas of the U.S. (e.g., much of the Rocky Mountains) have such sparse resources that an MSW and C&D cellulosic facility would not likely be justifiable. We did assume that in areas with other cellulosic feedstocks (forest and agricultural residue), that the MSW would be used even if the MSW could not justify the installation of a plant on its own. Therefore, we have estimated that urban waste could help contribute to the production of approximately 2.3 ethanol-equivalent billion gallons of fuel.[93] Note that some processes are likely to also process other portions of MSW (e.g., plastics, rubbers) into fuel, but we have only accounted for the portion expected to qualify as renewable fuel and produce RINs.

In addition to MSW and C&D waste generated from normal day-to-day activities, there is also potential for renewable biomass to be generated from natural disasters. This includes diseased trees, other woody debris, and C&D debris. For instance, Hurricane Katrina was estimated to have damaged approximately 320 million large trees.[94] Katrina also generated over 100 million tons of residential debris, not including the commercial sector. Much of this waste would likely be disposed of and therefore go unused. Collection of this material for the generation of biofuel could be a better alternative use for this waste. While we acknowledge this material could provide a large source in the short-term, natural disasters are highly variable, making it hard to predict amounts of material available in the future. Thus, for our analyses we have not included natural disaster renewable biomass in our estimates.

ii. *Agricultural and Forestry Residues*

The next category of feedstocks chosen will likely be those that are readily produced but have not yet been commercially collected. This includes both agricultural and forestry residues.

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[91] Wiltsee, G. , "Urban Wood Waste Resource Assessment," NREL/SR-570-25918, National Renewable Energy Laboratory, November 1998

[92] Biocycle, "The State of Garbage in America," Vol. 49, No. 12, December 2008, p. 22.

[93] Assuming 90 gal/dry ton ethanol conversion yield for urban waste in 2022

[94] Chambers, J., "Hurricane Katrina's Carbon Footprint on U.S. Gulf Coast Forests" *Science* Vol. 318, 2007.

Agricultural residues are expected to play an important role early on in the development of the cellulosic ethanol industry due to the fact that they are already being grown. Agricultural crop residues are biomass that remains in the field after the harvest of agricultural crops. The most common residues are corn stover (the stalks, leaves, and/or cobs) and straw from wheat, rice, barley, and oats. These U.S. crops and others produce more than 500 million tons of residues each year, although only a fraction can be used for fuel and/or energy production due to sustainability and conservation constraints.[95] Crop residues can be found all over the United States, but are primarily concentrated in the Midwest since corn stover accounts for half of all available agricultural residues.

Agricultural residues play an important role in maintaining and improving soil quality, protecting the soil surface from water and wind erosion, helping to maintain nutrient levels, and protecting water quality. Thus, collection and removal of agricultural residues raise concerns about the potential for increased erosion, reduced crop productivity, depletion of soil carbon and nutrients, and water pollution. Sustainable removal rates for agricultural residues have been estimated in various studies, many showing tremendous variability due to local differences in soil and erosion conditions, soil type, landscape (slope), tillage practices, crop rotation managements, and the use of cover crops. One of the most recent studies by top experts in the field shows that under current rotation and tillage practices, about 30% of corn stover (about 59 million metric tons) produced in the U.S. could be collected, taking into consideration erosion, soil moisture concerns, and nutrient replacement costs.[96] The same study shows that if farmers convert to no-till corn management and total stover production does not change, then approximately 50% of stover (100 million metric tons) could be collected without causing erosion to exceed the tolerable soil loss. This study, however, did not consider possible soil carbon loss which other studies indicate may be a greater constraint to environmentally sustainable feedstock harvest than that needed to control water and wind erosion.[97] Experts agree that additional studies are needed to further evaluate how soil carbon and other factors affect sustainable removal rates. Despite unclear guidelines for sustainable removal rates due to the uncertainties explained above, our agricultural modeling analysis assumes that no stover is removable on conventional tilled lands, 35% of stover is removable on conservation tilled lands, and 50% is removable on no-till lands. In general, these removal guidelines are appropriate only for the Midwest, where the majority of corn is currently grown.

As already noted, removal rates will vary by region due to local differences. Given the current understanding of sustainable removal rates, we believe that such assumptions are reasonably justified. Based on our research, we also note that calculating residue maintenance requirements for the amount of biomass that must remain on the land to ensure soil quality is another approach for modeling sustainable residue collection quantities. This approach would likely be more accurate for all landscapes as site-specific conditions such as soil type, topography, etc. could be taken into account. This would prevent site-specific soil erosion and

[95] Elbehri, Aziz. USDA, ERS. "An Evaluation of the Economics of Biomass Feedstocks: A Synthesis of the Literature. Prepared for the Biomass Research and Development Board," 2007; Since 2007, a final report has been released. Biomass Research and Development Board., "The Economics of Biomass Feedstocks in the United States: A Review of the Literature," October 2008.
[96] Graham, R.L., "Current and Potential U.S. Corn Stover Supplies," *American Society of Agronomy* 99:1-11, 2007.
[97] Wilhelm, W.W. et. al., "Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply," *Agron. J.* 99:1665-1667, 2007.

soil quality concerns that would inevitably exist when using average values for residue removal rates across all soils and landscapes. At the time of our analyses, however, we had limited data on which to accurately apply this approach and therefore assumed the removal guidelines based on tillage practices.

Our agricultural modeling (FASOM) suggests that corn stover will make up the majority of agricultural residues used by 2022 to meet the EISA cellulosic biofuel standard (4.9 ethanol-equivalent Bgal).[98] Smaller contributions are expected to come from other crop residues including sugarcane bagasse (0.6 ethanol-equivalent Bgal), wheat residues (0.1 ethanol-equivalent Bgal), and sweet sorghum pulp (0.1 ethanol-equivalent Bgal).[99]

The U.S. also has vast amounts of forest resources that could potentially provide feedstock for the production of cellulosic biofuel. One of the major sources of woody biomass could come from logging residues. The U.S. timber industry harvests over 235 million dry tons annually and produces large volumes of non-merchantable wood and residues during the process.[100] Logging residues are produced in conventional harvest operations, forest management activities, and clearing operations. In 2004, these operations generated approximately 67 million dry tons of forest residues that were left uncollected at harvest sites.[101] Other feedstocks include those from other removal residues, thinnings from timberland, and primary mill residues.

For the NPRM, FASOM was not able to model forestry biomass as a potential feedstock. As a result, we relied on USDA-Forest Service (FS) for information on the forestry sector at the time. For the final rule, we were able to incorporate the forestry sector model in FASOM. EISA does not allow forestry material from national forests and virgin forests that could be used to produce biofuels to count towards the renewable fuels requirement under EISA. Therefore, our modeling of forestry biomass excluded such material. The FASOM model estimated that approximately 0.1 ethanol-equivalent billion gallons would be produced from forestry biomass to meet EISA.

iii. *Dedicated Energy Crops*

While urban waste, agricultural residues and forest residues will likely be the first feedstocks used in the production of cellulosic biofuel, there may be limitations to their use due to land availability and sustainable removal rates. Energy crops which are not yet grown commercially but have the potential for high yields and a series of environmental benefits could help provide additional feedstocks in the future. Dedicated energy crops are plant species grown specifically for energy purposes. Various perennial plants have been researched as potential dedicated feedstocks, including switchgrass, mixed prairie grasses, hybrid poplar, miscanthus,

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[98] Assuming 92.3 gal/dry ton ethanol conversion yield for corn stover in 2022

[99] Bagasse is a byproduct of sugarcane crushing and not technically an agricultural residue. Sweet sorghum pulp is also a byproduct of sweet sorghum processing. We have included it under this heading for simplification due to sugarcane and sorghum being an agricultural feedstock.

[100] Smith, W. Brad et. al., "Forest Resources of the United States, 2002 General Technical Report NC-241," St. Paul, MN: U.S. Dept. of Agriculture, Forest Service, North Central Research Station, 2004.

[101] USDA-Forest Service. "Timber Products Output Mapmaker Version 1.0." 2004.

energy cane, energy sorghum, and willow trees. Refer to Section 1.1.2.2 of the RIA for more information on the benefits and challenges with using dedicated energy crops.

In addition to estimating the extent that agricultural residues might contribute to cellulosic ethanol production, FASOM also estimated the contribution that energy crops might provide (7.9 ethanol-equivalent Bgal).[102] FASOM covers all cropland and pastureland in production in the 48 contiguous United States. For the NPRM, FASOM did not contain all categories of grassland and rangeland captured in USDA's Major Land Use data sets. For the final rule, FASOM accounts for all major land categories, including forestland and rangeland. All crop production, including dedicated energy crops, takes place on cropland. Land categories that can be converted to cropland production include cropland pasture, forest pasture, and forestland. More detail can be found in Chapter VIII of this preamble. Furthermore, we constrained FASOM to be consistent with the 2008 Farm Bill and assumed 32 million acres would stay in Conservation Reserve Program (CRP).[103] Other models, such as USDA's Regional Environment and Agriculture Programming (REAP) model and University of Tennessee's POLYSYS model, have shown that the use of energy crops to meet EISA could be significant, similar to our FASOM modeling results for the final rule.[104]

iv. *Summary of Cellulosic Feedstocks for 2022*

Table IV.B.3-3 summarizes our internal estimate of the types of cellulosic feedstocks projected to be used and their corresponding volume contribution to 16 billion gallons cellulosic biofuel by 2022 for the purposes of our impacts assessment. The majority of feedstock is projected to come from dedicated energy crops. Other feedstocks include agricultural residues, forestry biomass, and urban waste.

[102] Assuming 16 Bgal cellulosic biofuel total, 2.3 Bgal from Urban Waste; 13.7 Bgal of cellulosic biofuel for ag residues, forestry biomass, and/or energy crops would be needed.
[103] Beside the economic incentive of a farmer payment to keep land in CRP, local environmental interests may also fight to maintain CRP land for wildlife preservation. Also, we did not know what portion of the CRP is wetlands which likely could not support harvesting equipment.
[104] Biomass Research and Development Initiative (BR&DI), "Increasing Feedstock Production for Biofuels: Economic Drivers, Environmental Implications, and the Role of Research," http://www.brdisolutions.com, December 2008.

Table IV.B.3-3
Cellulosic Feedstocks Assumed To Meet EISA In 2022[105]

Feedstock	Volume (Ethanol-equivalent Bgal)
Agricultural Residues	5.7
Corn Stover	4.9
Sugarcane Bagasse	0.6
Wheat Residue	0.1
Sweet Sorghum Pulp	0.1
Forestry Biomass	0.1
Urban Waste	2.3
Dedicated Energy Crops (Switchgrass)	7.9
Total 16.0	

4. Biodiesel & Renewable Diesel

Biodiesel and renewable diesel are replacements for petroleum diesel that are made from plant or animal fats. Biodiesel consists of fatty acid methyl esters (FAME) and can be used in low-concentration blends in most types of diesel engines and other combustion equipment with no modifications. The term renewable diesel covers fuels made by hydrotreating plant or animal fats in processes similar to those used in refining petroleum. Renewable diesel is chemically analogous to blendstocks already used in petroleum diesel, thus its use can be transparent and its blend level essentially unlimited. The goal of both biodiesel and renewable diesel conversion processes is to change the properties of a variety of feedstocks to more closely match those of petroleum diesel (such as its density, viscosity, and storage stability) for which the engines have been designed. The definition of biodiesel given in applicable regulations is sufficiently broad to be inclusive of both fuels.[106] However, the EISA stipulates that renewable diesel that is co-processed with petroleum diesel cannot be counted as biomass-based diesel for purposes of complying with the RFS2 volume requirements.[107]

In general, plant and animal oils are valuable commodities with many uses other than transportation fuel. Therefore we expect the primary limiting factor in the supply of both biodiesel and renewable diesel to be feedstock availability and price. Expansion of their market volumes is dependent on being able to compete on price with the petroleum diesel they are displacing, which will depend largely on continuation of current subsidies and other incentives.

[105] Volumes are represented here as ethanol-equivalent volumes, a mix of diesel and ethanol volumes as described in Section IV.A, above.
[106] See Section 1515 of the Energy Policy Act of 2005. More discussion of the definitions of biodiesel and renewable diesel are given in the preamble of the Renewable Fuel Standard rulemaking, Section II.B.2, as published in the Federal Register Vol.72, No. 83, p.23917.
[107] For more detailed discussion of the definition of coprocessing and its implications for compliance with EISA, see Section II.B.1 of this preamble.

Other biomass-based diesel fuel processes are at various stages of development, but due to uncertainty on production timelines, we didn't include these fuels in the biomass-based diesel impact assessments.

a. Historic and Projected Production

i. *Biodiesel*

As of November 2009, the aggregate production capacity of biodiesel plants in the U.S. was estimated at 2.8 billion gallons per year across approximately 191 facilities.[108] (However, at the time of this writing it is anticipated that capacity utilization will be approximately 17% for calendar year 2009.) Biodiesel plants exist in nearly all states, with the largest density of plants in the Midwest and Southeast where agricultural feedstocks are most plentiful.

Table IV.B.4-1 gives data on U.S. biodiesel production and use for recent years, including net domestic use after accounting for imports and exports. The figures suggest that the industry has grown out of proportion with actual biodiesel demand. Reasons for this include various state incentives to build plants, along with state and federal incentives to blend biodiesel, which have given rise to an optimistic industry outlook over the past several years. Since the cost of capital is relatively low for the biodiesel production process (typically four to six percent of the total per-gallon cost), this industry developed along a path of more small, privately-owned plants in comparison to the ethanol industry, with median size less than 10 million gallons/yr.[109] These small plants, with relatively low costs other than feedstock, have generally been able to survive producing well below their nameplate capacities.

Table IV.B.4-1
Summary of U.S. Biodiesel Production and Use (million gallons)[110]

Year	Domestic production capacity	Domestic total production	Apparent capacity utilization	Net domestic biodiesel use	Net domestic use as percent of production
2004	245	28	11%	27	96%
2005	395	91	23%	91	100%
2006	792	250	32%	261	104%
2007	1,809	490	27%	358	73%
2008	2,610	776	30%	413	53%
2009	2,806	475 (est.)	17%	296 (est.)	62%

Some of this industry capacity may not be dedicated specifically to fuel production, instead being used to make oleochemical feedstocks for further conversion into products such as

[108] Capacity data taken from National Biodiesel Board as of November 2009.
[109] Assessment of plant capital cost based on USDA production cost models. A publication describing USDA modeling of biodiesel production costs can be found in Bioresource Technology 97(2006) 671-8.
[110] Capacity data taken from National Biodiesel Board as of November 2009. Production, import, and export figures taken from EIA Monthly Energy Review, Table 10.4 as of December 2009.

surfactants, lubricants, and soaps. These products do not show up in renewable fuel sales figures.

During 2004-2006, demand for biodiesel grew rapidly, but the trend of increasing sales was quickly surpassed by construction and start-up of new plants Since then, periods of high commodity prices followed by reduced demand for transportation fuel during the economic downturn have caused additional strain on the industry beyond the overcapacity situation. Biodiesel producers were able to find additional markets overseas, and a significant portion of the 2007 and 2008 production was exported to Europe where fuel prices and additional tax subsidies helped offset high feedstock costs. However, the EU enacted a tariff to protect domestic producers early in 2009, after which exports dropped to a small fraction of production.[111] We understand there may be some additional export markets developing within North America, but given the uncertainty at this time, we do not account for any biodiesel exports in our projections.

To perform our impacts analyses for this rule, it was necessary to forecast the state of the biodiesel industry in the timeframe of the fully-phased-in RFS. In general, this consisted of reducing the industry capacity to be much closer to 1.67 billion gallons per year by 2022 (based on the volume requirements to meet the standard; see Section IV.A.2). This was accomplished by considering as screening factors the current production and sales incentives in each state as well as each plant's primary feedstock type and whether it was BQ-9000 certified.[112] Going forward producers will compete for feedstocks and markets may consolidate. During this period the number of operating plants is expected to shrink, with surviving plants utilizing feedstock segregation and pre-treatment capabilities, giving them flexibility to process any mix of feedstocks available in their area. By the end of this period we project a mix of large regional plants and some smaller plants taking advantage of local market niches, with an overall average capacity utilization around 85%. Table IV.B.4-2 summarizes this forecast. See Section 1.5.4 of the RIA for more details.

Table IV.B.4-2
Summary of Projected Biodiesel Industry Characterization Used in Our Analyses [113]

2008		2022
Total production capacity on-line (million gal/yr)	2,610	1,968
Number of operating plants	176	121
Median plant size (million gal/yr)	5	5
Total biodiesel production (million gal)	776	1,670
Average plant utilization	0.30	0.85

ii. *Renewable Diesel*

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[111] *Ibid.*

[112] Information on state incentives was taken from U.S. Department of Energy website, accessed July 30, 2008, at http://www.eere.energy.gov/afdc/fuels/biodiesel_laws.html. Information on feedstock and BQ-9000 status was taken from Biodiesel Board fact sheet, accessed July 30, 2008.

[113] 2008 capacity data taken from National Biodiesel Board; production figures taken from EIA Monthly Energy Review, Table 10.4 as of October 2009.

Renewable diesel is a fuel (or blendstock) produced from animal fats, vegetable oils, and waste greases using chemical processes similar to those employed in petroleum hydrotreating. These processes remove oxygen and saturate olefins, converting the triglycerides and fatty acids into paraffins. Renewable diesel typically has higher cetane, lower nitrogen, and lower aromatics than petroleum diesel fuel, while also meeting stringent sulfur standards.

As a result of the oxygen and olefins in the feedstock being removed, renewable diesel has storage, stability, and shipping properties equivalent to petroleum diesel. This allows renewable diesel fuel to be shipped in existing petroleum pipelines used for transporting fuels, thus avoiding a significant issue with distribution of biodiesel. For more on fuel distribution, refer to Section IV.C.

Considering that this industry is still in development and that there are no long-term projections of production volume, we base our volume estimate of 150 MMgal/yr primarily on recent industry project announcements involving proven technology. Due to the current status of tax incentives, we project all of this fuel will be produced at stand-alone facilities.

b. Feedstock Availability

Publically available industry information along with agricultural commodity modeling we have done for this rule (see Section VIII.A) suggests that the three largest sources of feedstock for biodiesel will be rendered animal fats, soy oil, and corn oil extracted from dry mill ethanol facilities. Renewable diesel plants are expected to use solely animal fats due to the fact that these feedstocks are cheaper than vegetable oils and the process can handle them without issue. Comments we have received from a large rendering company suggest there will be adequate fats and greases feedstocks to supply biofuels as well as other historical uses. Table IV.B.4-3 summarizes the feedstock types, process types, and volumes projected to be used in 2022 for biodiesel and renewable diesel. More details on feedstock sources and volumes are presented in Section 1.1.3 of the RIA.

Table IV.B.4-3
Summary of Projected Biodiesel and Renewable Diesel Feedstock Use in 2022 (MMgal)

Feedstock type	Base catalyzed biodiesel	Acid-pretreatment biodiesel	Renewable diesel
Virgin vegetable oil	660	-	-
Corn oil from ethanol production	-	680	-
Rendered animal fats and greases	-	230	150
Algae oil or other advanced source	100	-	-

C. Biofuel Distribution

The current motor fuel distribution infrastructure has been optimized to facilitate the movement of petroleum-based fuels. Consequently, there are very efficient pipeline-terminal networks that move large volumes of petroleum-based fuels from production/import centers on the Gulf Coast and the Northeast into the heartland of the country. In contrast, most biofuel is produced in the heartland of the country and needs to be shipped to the coasts, flowing roughly in the opposite direction of petroleum-based fuels. In addition, while some renewable fuels such as hydrocarbons may be transparent to the distribution system, the physical/chemical nature of other renewable fuels may limit the extent to which they can be shipped/stored fungibly with petroleum-based fuels. The vast majority of biofuels are currently shipped by rail, barge and tank truck to petroleum terminals. All biofuels are currently blended with petroleum-based fuels prior to use.[114] Most biofuel blends can be used in conventional vehicles. However, E85 can only be used in flex-fuel vehicles, requires specially-constructed retail dispensing/storage equipment, and may require special blendstocks at terminals. These factors limit the ability of biofuels to utilize the existing petroleum fuel distribution infrastructure. Hence, the distribution of renewable fuels raises unique concerns and in many instances requires the addition of new transportation, storage, blending, and retail equipment.

1. Biofuel Shipment to Petroleum Terminals

Ethanol currently is not commonly shipped by pipeline because it can cause stress corrosion cracking in pipeline walls and its affinity for water and solvency can result in product contamination concerns. A short gasoline pipeline in Florida is currently shipping batches of ethanol and other more extensive pipeline systems have feasibility studies underway.[115] Thus, existing petroleum pipelines in some areas of the country may play an increasing role in the shipment of ethanol. Evaluations are also currently underway regarding the feasibility of constructing a new dedicated ethanol pipeline from the Midwest to the East coast. We expect that cellulosic distillate fuels will not have materials compatibility issues with the existing petroleum fuel distribution infrastructure. Thus, there may be more opportunity for cellulosic distillate fuel to be shipped by pipeline. However, the location of both ethanol and cellulosic distillate production facilities relative to the origination points for existing petroleum pipelines will be a limiting factor regarding the extent to which pipelines can be used.

Our analysis of the shipment of ethanol and cellulosic distillate fuels to petroleum terminals is based on the projections of the location of biofuel production facilities and end use areas contained in the NPRM. We assume that the majority of ethanol and cellulosic distillate fuel would be produced in the Midwest, and that both fuels would be shipped to petroleum terminals in a similar fashion (by rail, barge, and tank truck). To the extent which new biofuel production facilities are more dispersed than projected in the NPRM, there may be more opportunity for both fuels to be used closer to their point of manufacture. This potential benefit would primarily apply to cellulosic ethanol and distillate production facilities given that such facilities have yet to be constructed, whereas most corn-ethanol production facilities have already been constructed in the Midwest.

Biodiesel is currently not typically shipped by pipeline due to concerns that it may contaminate jet fuel that is shipped on the same pipeline and potential incompatibility with pipeline gaskets and seals. Kinder Morgan's Plantation pipeline is currently shipping B5 blends

[114] The prescribed blending ratio for a given biofuel is based on vehicle compatibility and emissions considerations. Some biofuels may be found to be suitable for use without the need for blending with petroleum-based fuel.
[115] Shipment of ethanol in pipelines that carry distillate fuels as well as gasoline presents additional challenges.

on segments of its system that do not handle jet fuel. The shipment of biodiesel by pipeline may become more widespread and might be expanded to systems that handle jet fuel. However, the relatively small production volumes from individual biodiesel plants and the widespread location of such production facilities will tend to limit the extent to which biodiesel may be shipped by pipeline.

Due to the uncertainties regarding the extent to which pipelines might participate in the transportation of biofuels in the future, we assumed that biofuels will continue to be transported by rail, barge, and truck to petroleum terminals as the vast majority of biofuel volumes are today. To the extent that pipelines do play an increasing role in the distribution of ethanol, this may improve reliability in supply and reduce distribution costs. Apart from increased shipment by pipeline, biofuel distribution, and in particular ethanol distribution can be further optimized primarily through the expanded use of unit trains.[116] We anticipate that the vast majority of ethanol and cellulosic distillate facilities will be sized to facilitate unit train service.[117] We do not expect that biodiesel facilities will be of sufficient size to justify shipment by unit train. In the NPRM, we projected that unit train receipt facilities would be located at petroleum terminals and existing rail terminals. Based on industry input regarding the logistical hurdles in locating unit train receipt facilities at petroleum/existing rail terminals, we expect that such facilities will be constructed on dedicated property with rail access that is as close to petroleum terminals as practicable.[118]

Shipment of biofuels by manifest rail to existing rail terminals will continue to be an important means of supplying biofuels to distant markets where the volume of the production facility and/or the local demand is not sufficient to justify shipment by unit train.[119] Shipments by barge will also play an important role in those instances where production and demand centers have water access and in some cases as the final link from a unit train receipt facility to a petroleum terminal. Direct shipment by tank truck from production facilities to petroleum terminals will also continue for shipment over distances shorter than 200 miles.

We project that most biofuel volumes shipped by rail will be delivered to petroleum terminals by tank truck.[120] We expect that this will always be the case for manifest rail shipments. In the NPRM, we projected that trans-loading of biofuels from rail cars to tank trucks would be an interim measure until biofuel storage tanks were constructed.[121] Based on industry input, we now expect trans-loading will be a long-term means of transferring manifest rail car shipments of biofuels received at existing rail terminals to tank trucks for delivery to petroleum terminals. We also anticipate that trans-loading will be used at some unit train receipt facilities,

[116] Unit trains are composed of 70 to 100 rail cars that are dedicated to shuttle back and forth from production facilities downstream receipt facilities near petroleum terminals.
[117] A facility exists in Iowa to consolidate rail cars of ethanol from some ethanol plants that are not large enough to support unit train service by themselves.
[118] Existing unit train receipt facilities have primarily followed this model.
[119] Manifest rail shipment refers to the shipment of rail cars of biofuels in trains that also carry other products.
[120] At least one current ethanol unit train receipt facility has a pipeline link to a nearby terminal. To the extent that additional unit train receipt facilities could accomplish the final link to petroleum terminals by pipeline, this would significantly reduce the need for shipment by tank truck.
[121] Trans-loading refers to the direct transfer of the contents of a rail car to a tank truck without the intervening delivery into a storage tank.

although we expect that most of these facilities will install biofuel storage tanks from which tank trucks will be filled for delivery to petroleum terminals. Imported biofuels will typically be received and be further distributed by tank truck from petroleum terminals that already have receipt facilities for waterborne fuel shipments.

We anticipate that the deployment of the necessary distribution infrastructure to accommodate the shipment of biofuels to petroleum terminals is achievable.[122] We believe that construction of the requisite rail cars, barges, tank trucks, tank truck and rail/barge/truck receipt facilities is within the reach of corresponding construction firms.[123] Although shipment of biofuels by rail represents a major fraction of all biofuel ton-miles, it is projected to account for approximately 0.4% of all rail freight by 2022. Many improvements to the freight rail system will be required in the next 15 years to keep pace with the large increase in the overall freight demand. Given the broad importance to the U.S. economy of meeting the anticipated increase in freight rail demand, and the substantial resources that seem likely to be focused on this cause, we believe that overall freight rail capacity would not be a limiting factor to the successful implementation of the biofuel requirements under EISA.

2. Petroleum Terminal Accommodations

Terminals will need to install additional storage capacity to accommodate the volume of biofuels that we anticipate will be used in response to the RFS2 standards. Petroleum terminals will also need to install truck receipt facilities for biofuels and equipment to blend biofuels into petroleum-based fuels. Upgrades to barge receipt facilities to handle deliveries of biofuels may also be needed at petroleum terminals with water access. Biodiesel storage and blending facilities will need to be insulated/heated in cold climates to prevent biodiesel from gelling.[124] Questions have been raised about the ability of some terminals to install the needed storage capacity due to space constraints and difficulties in securing permits.[125] Overall demand for fuel used in motor vehicles is expected to remain relatively constant through 2022. Thus, much of the increased demand for biofuel storage could be accommodated by modifying storage tanks previously used for the gasoline and petroleum-based diesel fuels that would displaced by biofuels. The areas served by existing terminals also often overlap. In such cases, one terminal might be space constrained while another serving the same area may be able to install the additional capacity to meet the increase in demand. In cases where it is impossible for existing terminals to expand their storage capacity due to a lack of adjacent available land or difficulties in securing the necessary permits, new satellite storage or new separate terminal facilities may be needed for additional storage of biofuels. However, we believe that there would be few such situations.

In the NPRM, we stated the current EPA policy that the RFG and anti-dumping regulations currently require certified gasoline to be blended with denatured ethanol to produce

[122] See Section 1.6 of the RIA for additional discussion of the challenges in distributing biofuels from the production/import facility to the end user.
[123] Vessels that transport biodiesel will need to be heated/insulated in cold climates to prevent gelling.
[124] Some terminals are avoiding the need for heated/insulated biodiesel facilities by storing high biodiesel blends (e.g. B50) for blending with petroleum-based diesel fuel.
[125] The Independent Fuel Terminal Operators Association represents terminals in the Northeast.

E85. We also stated that if terminal operators add blendstocks to finished gasoline for use in manufacturing E85, the terminal operator would need to register as a refiner with EPA and meet all applicable standards for refiners. Commenters questioned these statements. As we are not taking any action in this final rule with respect to policies surrounding E85, we will consider these comments outside the context of this rule.

3. <u>Potential Need for Special Blendstocks at Petroleum Terminals for E85</u>

ASTM International is considering a proposal to lower the minimum ethanol concentration in E85 to facilitate meeting ASTM minimum volatility specifications in cold climates and when only low vapor pressure gasoline is available at terminals.[126] Commenters have stated that the current proposal to lower the minimum ethanol concentration to 68 volume percent may not be sufficient for this purpose. ASTM International may consider an additional proposal to further decrease the minimum ethanol concentration. Absent such an adjustment, a high-vapor pressure petroleum-based blendstock such as butane would need to be supplied to most petroleum terminals to produce E85 that meets minimum volatility specifications. In such a case, butane would need to be transported by tank truck from petroleum refineries to terminals and storage and blending equipment would be needed at petroleum terminals.[127]

Instead of lowering the minimum ethanol concentration of E85, some stakeholders are discussing establishing a new high-ethanol blend for use in flex-fuel vehicles. Such a fuel would have a minimum ethanol concentration that would be sufficient to allow minimum volatility specifications to be satisfied while using finished gasoline that is already available at petroleum terminals.[128] E85 would continue to be marketed in addition to this new fuel for use in flex-fuel vehicles when E85 minimum volatility considerations could be satisfied.

We believe that industry will resolve the concerns over the ability to meet the minimum volatility needed for high-ethanol blends used in flex-fuel vehicles in a manner that will not necessitate the use of high-vapor pressure blendstocks in their manufacture. Nevertheless, petroleum terminals may find it advantageous to blend butane into E85 because of the low cost of butane relative to gasoline provided that the cost benefit outweighs the associated butane distribution costs.[129]

4. <u>Need for Additional E85 Retail Facilities</u>

The number of additional E85 retail facilities needed to consume the volume of ethanol used under EISA varies substantially depending on the control case. Under our primary mid-ethanol scenario, we estimate that by 2022 an additional 19,765 E85 retail facilities would be needed relative to the AEO reference case to enable the consumption of the ethanol that we

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[126] Minimum volatility specifications were established by ASTM to address safety and vehicle driveability considerations.
[127] See Section 1.6 of the RIA for a discussion of the potential distribution of butane to petroleum terminals for blending with E85 and Section 4.2 for the potential costs.
[128] Such a new fuel might have a lower ethanol concentration of 60% and a maximum ethanol concentration of 85%.
[129] EPA may consider reevaluating its policies regarding the blendstocks used in the manufacture of E85 to facilitate this practice.

project would be used in E85.[130] Under the high-ethanol scenario, we estimate that an additional 23,809 E85 facilities would be needed and that 4,500 E85 facilities that would otherwise be in place would need to be upgraded to include more E85 dispensers by 2022. Whereas under the low-ethanol volume scenario, we project that 11,677 additional E85 facilities would be needed by 2022.

On average, approximately 1,520 additional E85 facilities will be needed each year from 2010 through 2022 under our primary scenario. Under the high and low ethanol scenarios, an additional 1,820 and 900 E85 retail facilities per year respectively would be needed. Under the high ethanol case and to a lesser extent under the primary case, this represents an aggressive timeline for the addition of new E85 facilities given that there are approximately 2,000 E85 retail facilities in service today. Nevertheless, we believe the addition of these new E85 facilities may be possible for the industries that manufacture and install E85 retail equipment. Underwriters Laboratories requires that E85 refueling dispenser systems must be certified as complete units.[131] To date, no complete E85 dispenser systems have been certified by UL. We understand that all the fuel dispenser components with the exception of the hoses that connect to the refueling nozzle have successfully passed the necessary testing. There does not appear to be a technical difficulty in finding hoses that can pass the required testing. Therefore, we anticipate this situation will be resolved once the demand for new E85 facilities is demonstrated. Hence, we believe that the current lack of a UL certification for complete E85 dispenser systems will not impede the installation of the additional E85 facilities that we projected will be needed.

Petroleum retailers expressed concerns about their ability to bear the cost installing the needed E85 refueling equipment given that most retailers are small businesses and have limited capital resources. They also expressed concern regarding their ability to discount the price of E85 relative to E10 sufficiently to persuade flexible fuel vehicle owners to choose E85 given the lower energy density of ethanol. Today's rule does not contain a requirement for retailers to carry E85. We understand that retailers will only install E85 facilities if they can be assured of sufficient E85 throughput to recover their capital costs. The current projections regarding the future cost of gasoline relative to ethanol indicate that it may be possible to price E85 in a competitive fashion to E10. Thus, demand for E85 may be sufficient to encourage retailers to install the needed E85 refueling facilities.

D. Ethanol Consumption

1. Historic/Current Ethanol Consumption

Ethanol and ethanol-gasoline blends have a long history as automotive fuels. In fact, the well-known Model-T was capable of running on both ethanol and gasoline.[132] However,

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[130] See Section 1.6 of the RIA for a discussion of the projected number of E85 refueling facilities that would be needed. There would need to be a total of 24,265 E85 retail facilities under the primary scenario, 4,500 of which are projected to have been placed in service absent the RFS2 standards under the AEO reference case. Our analysis assumes the installation of new dispensers and underground storage tank (UST) systems for E85. EPA's Office of Underground Storage Tanks requires that UST systems must be compatible with the fuel stored. Authorities who Have Jurisdiction (such as local fire marshals) typically require that fuel dispensers be listed by an organization such as Underwriters Laboratories.

[131] See http://ulstandardsinfonet.ul.com/outscope/0087A.html

inexpensive crude oil prices kept ethanol from making a significant presence in the transportation sector until the end of the 20th century. Over the past decade, ethanol use has grown rapidly due to oxygenated fuel requirements, MTBE bans, tax incentives, state mandates, the first federal renewable fuels standard ("RFS1"), and rising crude oil prices. Although the cost of crude has come down since reaching record levels in 2008, uncertainty surrounding pricing and the environmental implications of fossil fuels continue to drive ethanol use.

A record 9.5 billion gallons of ethanol were blended into U.S. gasoline in 2008 and EIA is forecasting additional growth in the years to come.[133] According to their recently released Short-Term Energy Outlook (STEO), EIA is forecasting 0.7 million barrels of daily ethanol use in 2009, which equates to 10.7 billion gallons. The October 2009 STEO projects that total ethanol usage (domestic production plus imports) will reach 12.1 billion gallons by 2010.[134]

The National Petrochemical and Refiners Association (NPRA) estimates that ethanol is currently blended into about 75 percent of all gasoline sold in the United States.[135] The vast majority is blended as E10 or 10 volume percent ethanol, although a small amount is blended as E85 for use in flexible fuel vehicles (FFVs).

Complete saturation of the gasoline market with E10 is referred to as the ethanol "blend wall." The height of the blend wall in any given year is directly related to gasoline demand. In AEO 2009, EIA projects that gasoline demand will peak around 2013 and then start to taper off due to vehicle fuel economy improvements. Based on the primary ethanol growth scenario we're forecasting under today's RFS2 program, the nation is expected to hit the 14-15 billion gallon blend wall by around 2014 (refer ahead to Figure IV.D.2-1), although it could be sooner if gasoline demand is lower than expected. It could also be lower if projected volumes of non-ethanol renewables do not materialize and ethanol usage is higher than expected.

Over the years there have been several policy attempts to increase FFV sales including Corporate Average Fuel Economy (CAFE) credits and government fleet alternative-fuel vehicle requirements. As a result, there are an estimated 8 million FFVs on the road today, up from just over 7 million in 2008. While this is not insignificant in terms of growth, FFVs continue to make up less than 4 percent of the total gasoline vehicle fleet. In addition, E85 is only currently offered at about 1 percent of gas stations nationwide. Ethanol consumption is currently limited by the number of FFVs on the road and the number of E85 outlets or, more specifically, the number of FFVs with access to E85. Still many FFV owners with access to E85 are not choosing it because it is currently priced almost 40 cents per gallon higher than conventional gasoline on an energy equivalent basis.[136] According to EIA, only 12 million gallons of E85 were consumed in 2008.[137]

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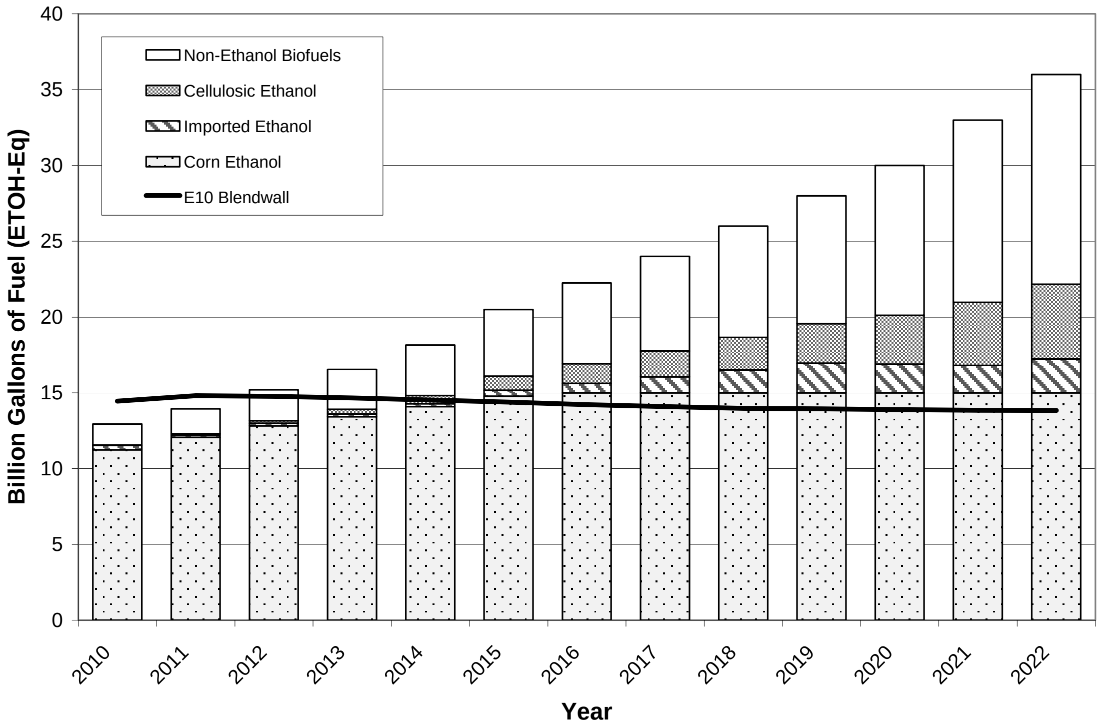
132 The Model T was also capable of running on kerosene.
133 EIA, Monthly Energy Review, September 2009 (Table 10.2b).
134 Letter from Richard Newell, EIA Administrator to Lisa Jackson, EPA Administrator dated October 29, 2009 (Table 1).
135 Based on comments provided by NPRA (EPA-HQ-OAR-2005-0161-2124.1).
136 Based on average E85 and regular unleaded gasoline prices reported at http://www.fuelgaugereport.com/ on November 23, 2009
137 EIA, Annual Energy Outlook 2009 – ARRA Update (Table 2).

To meet today's RFS2 requirements we are going to need to see growth in FFV and E85 infrastructure as well as changes in retail pricing and consumer behavior. However, the amount of change needed is proportional to the amount of ethanol observed under the RFS2 program. As explained in Section IV.A, EPA expects total ethanol demand could be anywhere from 17.5 to 33.2 billion gallons in 2022, depending on the amount of non-ethanol cellulosic biofuels that are realized. The low-ethanol case would require only moderate changes in FFV/E85 infrastructure and refueling whereas the high-ethanol case would require very dramatic changes and likely a mandate. For the final rule, we have chosen to focus our impact analyses on the primary mid-ethanol case of 22.2 billion gallons. A discussion of how this volume of ethanol could be consumed in 2022 with expanded FFV/E85 infrastructure is presented below. As expected, the infrastructure changes required under this FRM scenario are less extreme than those highlighted in the proposal based on a predominant ethanol world (34.2 billion gallons of ethanol). However, there are additional technological, logistical and financial barriers that will need to be overcome with respect to commercialization of BTL and non-ethanol cellulosic biofuels. For more on cellulosic diesel technologies, distribution impacts, and production costs, refer to Sections 1.4, 1.6 and 4.1 of the RIA.

2. Increased Ethanol Use under RFS2

Under the primary ethanol growth scenario considered as part of today's rule, ethanol consumption will need to be about three times higher than RFS1 levels, more than twice as much as today's levels, and 9 billion gallons higher than the ethanol predicted to occur in 2022 absent RFS2 (according to AEO 2007). To get to 22.2 billion gallons of ethanol use according to the potential ramp-up described in Section 1.2 of the RIA, the nation is predicted to hit the blend wall in 2014 as shown below in Figure IV.D.2-1.

Figure IV.D.2-1
RFS2 Primary Control Case Compared to E10 Blend Wall



As shown above, we are anticipating almost 14 billion gallons of non-ethanol advanced biofuels under today's RFS2 program. But overall, ethanol is expected to continue to be the nation's primary biofuel with over 22 billion gallons in 2022. To get beyond the blend wall and consume more than 14-15 billion gallons of ethanol, we are going to need to see increases in the number FFVs on the road, the number of E85 retailers, and the FFV E85 refueling frequency.

It is possible that conventional gasoline (E0) could continue to co-exist with E10 and E85 for quite some time. However, for analysis purposes, we have assumed that E10 would replace E0 as expeditiously as possible and that all subsequent ethanol growth would come from E85. Furthermore, we assumed that no ethanol consumption would come from the mid-level ethanol blends (e.g., E15) under our primary control case since they are not currently approved for use in non-FFVs. However, as a sensitivity analysis, we have examined the impacts that E15 would have on ethanol consumption (refer to Section IV.D.3).

a. Projected Gasoline Energy Demand

The maximum amount of ethanol our country is capable of consuming in any given year is a function of the total gasoline energy demanded by the transportation sector. Our nation's gasoline energy demand is dependent on the number of gasoline-powered vehicles on the road, their average fuel economy, vehicle miles traveled (VMT), and driving patterns. For analysis purposes, we relied on the gasoline energy projections provided by EIA in the AEO 2009 final release.[138] AEO 2009 takes the fuel economy improvements set by EISA into consideration and also assumes a slight dieselization of the light-duty vehicle fleet.[139] It also takes the recession's impacts on driving patterns into consideration. The result is a 25% reduction in the projected 2022 gasoline energy demand from AEO 2007 (a pre-EISA world) to AEO 2009.[140] EIA essentially has total gasoline energy demand (petroleum-based gasoline plus ethanol) flattening out, and even slightly decreasing, as we move into the future.

b. Projected Growth in Flexible Fuel Vehicles

Over one million FFVs were sold in both 2008 and 2009 according to EPA certification data. Despite the recession and current state of the auto industry, automakers are incorporating more and more FFVs into their light-duty production plans. While the FFV system (i.e., fuel tank, sensor, delivery system, etc.) used to be an option on some vehicles, most automakers are moving in the direction of converting entire product lines over to E85-capable systems. Still, the number of FFVs that will be manufactured and purchased in future years is uncertain.

To measure the impacts of increased volumes of renewable fuel, we considered three different FFV production scenarios that might correspond to the three biofuel control cases

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[138] EIA, Annual Energy Outlook 2009 - ARRA Update (Table 2).
[139] The gasoline energy demand forecast provided in AEO 2009 – ARRA Update is reasonably consistent with the recently Proposed Rulemaking To Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards (referred to hereafter as the "Light-Duty Vehicle GHG Rule." For more information on the Light-Duty Vehicle GHG Rule, refer to 74 FR 49454 (September 28, 2009).
[140] EIA, Annual Energy Outlooks 2007 & 2009 – ARRA Update (Table 2).

analyzed for the final rule. For all three cases, we assumed that total light-duty vehicle sales would follow AEO 2009 trends. The latest EIA report suggests lower than average sales in 2008-2013 (less than 16 million vehicles per year) before rebounding and growing to over 17 million vehicles by 2019.[141] These vehicle projections are consistent with EPA's recently proposed Light-Duty Vehicle GHG Rule.[142]

Although we assumed total vehicle and car/truck sales would be the same in all three cases, we assumed varying levels of FFV production. For our low-ethanol control case, we assumed steady business-as-usual FFV growth according to AEO 2009 predictions.[143] For our primary mid-ethanol control case, we assumed increased FFV sales under the presumption that GM, Ford and Chrysler (referred to hereafter as the "Detroit 3") would follow through with their commitment to produce 50% FFVs by 2012. Despite the current state of the economy and the hardships facing the auto industry (GM and Chrysler filed for bankruptcy earlier this year), the Detroit 3 appear to still moving forward with their voluntary FFV commitment.[144] Under our primary control case, we assumed that non-domestic FFVs sales would track around 2%, consistent with today's production/plans.[145] Finally, for our high-ethanol control case, we assumed a theoretical 80% FFV mandate based on the Open Fuel Standard Act of 2009 that was reintroduced in Congress on March 12, 2009.[146] Given today's reduced vehicle sales and gasoline demand, we believe a mandate would be the only viable means for consuming 32.2 billion gallons of ethanol in 2022.

Under our primary mid-ethanol control case, total FFV sales are estimated at just over 4 million vehicles per year in 2017 and beyond. This is less aggressive than the assumptions made in the NPRM. At that time, we were expecting more cellulosic ethanol which could justify higher FFV production assumptions. We assumed that not only would the Detroit 3 fulfill their 50% by 2012 FFV production commitment, non-domestic automakers might follow suit and produce 25% FFV in 2017 and beyond. We also assumed that annual light-duty vehicle sales would continue around the historical 16 million vehicle mark resulting in 6 million FFVs in 2017 and beyond.

Based on our revised vehicle/FFV production assumptions coupled with vehicle survival rates, VMT, and fuel economy estimates applied in the recently proposed Light-Duty Vehicle GHG Rule, the maximum percentage of fuel (gasoline/ethanol mix) that could feasibly be consumed by FFVs in 2022 would be about 20% (down from 30% in the NPRM). For more information on our FFV production assumptions and fuel fraction calculations, refer to Section 1.7.2 of the RIA.

[141] EIA, Annual Energy Outlook 2009 - ARRA Update (Table 47).
[142] Rulemaking to Establish Light-Duty Vehicle GHG Emission Standards and Corporate Average Fuel Economy Standards, 74 FR 49454 (September 28, 2009).
[143] EIA, Annual Energy Outlook 2009 - ARRA Update (Table 47).
[144] Ethanol Producer Magazine, "Automakers Maintain FFV Targets in Bailout Plans." February 2009. This is consistent with information provided in GM and Chrysler's restructuring plans submitted to the U.S. Department of Treasury on February 17, 2009.
[145] Based on 2008 FFV certification data and 2009 projections based on the National Ethanol Vehicle Coalition, 2009 FFV Purchasing Guide.
[146] A copy of H.R. 1476 can be found at: http://www.opencongress.org/bill/111-h1476/text

c. Projected Growth in E85 Access

According to the National Ethanol Vehicle Coalition (NEVC), there are currently 2,100 gas stations offering E85 in 44 states plus the District of Columbia.[147] While this represents significant industry growth, it still only translates to 1.3% of U.S. retail stations nationwide carrying the fuel.[148] As a result, most FFV owners clearly do not have reasonable access to E85. For our FFV/E85 analysis, we have defined "reasonable access" as one-in-four pumps offering E85 in a given area.[149] Accordingly, just over 5% of the nation currently has reasonable access to E85, up from 4% in 2008 (based on a mid-year NEVC pump estimate).[150]

There are a number of states promoting E85 usage by offering FFV/E85 awareness programs and/or retail pump incentives. A growing number of states are also offering infrastructure grants to help expand E85 availability. Currently, 10 Midwest states have adopted a progressive Energy Security and Climate Stewardship Platform.[151] The platform includes a Regional Biofuels Promotion Plan with a goal of making E85 available at one third of all stations by 2025. In addition, the American Recovery and Reinvestment Act of 2009 (ARRA or Recovery Act) recently increased the existing federal income tax credit from $30,000 or 30% of the total cost of improvements to $100,000 or 50% of the total cost of needed alternative fuel equipment and dispensing improvements.[152]

Given the growing number of subsidies, it is clear that E85 infrastructure will continue to expand in the future. However, like FFVs, we expect that E85 station growth will be somewhat proportional to the amount of ethanol realized under the RFS2 program. As such, we analyzed three different E85 growth scenarios for the final rule that could correspond to the three different RFS2 control cases. As an upper bound for our high-ethanol control case, we maintained the 70% access assumption we applied for the NPRM. This is roughly equivalent to all urban areas in the United States offering reasonable (one-in-four-station) access to E85.[153] For our other control cases we assumed access to E85 would be lower with the logic that retail stations (the majority of which are independently owned and operated and net around $30,000 per year) would not invest in more E85 infrastructure than what was necessary to meet the RFS2 requirements. For our primary mid-ethanol control case we assumed reasonable access would grow from 4% in 2008 to 60% in 2022 and for our low-ethanol control case we assumed that

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[147] NEVC website, accessed on November 23, 2009

[148] Based on National Petroleum News gasoline station estimate of 161,768 in 2008.

[149] For a more detailed discussion on how we derived our one-in-four reasonable access assumption, refer to Section 1.6 of the RIA. For the distribution cost implications as well as the cost impacts of assuming reasonable access is greater than one-in-four pumps, refer to Section 4.2 of the RIA.

[150] Computed as percent of stations with E85 (2,101/161,768 as of November 2009 or 1,733/161,768 as of August 2008) divided by 25% (one-in-four stations).

[151] The following states have adopted the plan: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota and Wisconsin. For more information, visit: http://www.midwesterngovernors.org/resolutions/Platform.pdf

[152] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf

[153] For this analysis, we've defined "urban" as the top 150 metropolitan statistical areas according to the U.S. census and/or counties with the highest VMT projections according the EPA MOVES model, all RFG areas, winter oxy-fuel areas, low-RVP areas, and other relatively populated cities in the Midwest.

access would only grow to 40% by 2022. As discussed in Section IV.C, we believe these E85 growth scenarios are possible based on our assessment of distribution infrastructure capabilities.

d. Required Increase in E85 Refueling Rates

As mentioned earlier, there were just over 7 million FFVs on the road in 2008. If all FFVs refueled on E85 100% of the time, this would translate to about 8.3 billion gallons of E85 use.[154] However, E85 usage was only around 12 million gallons in 2008.[155] This means that, on average, FFV owners were only tapping into about 0.15% of their vehicles' E85/ethanol usage potential last year. Assuming that only 4% of the nation had reasonable one-in-four access to E85 in 2008 (as discussed above), this equates to an estimated 4% E85 refueling frequency for those FFVs that had reasonable access to the fuel.

There are several reasons behind today's low E85 refueling frequency. For starters, many FFV owners may not know they are driving a vehicle that is capable of handling E85. As mentioned earlier, more and more automakers are starting to produce FFVs by engine/product line, e.g., all 2008 Chevy Impalas are FFVs.[156] Consequently, consumers (especially brand loyal consumers) may inadvertently buy a flexible fuel vehicle without making a conscious decision to do so. And without effective consumer awareness programs in place, these FFV owners may never think to refuel on E85. In addition, FFV owners with reasonable access to E85 and knowledge of their vehicle's E85 capabilities may still not choose to refuel on E85. They may feel inconvenienced by the increased refueling requirements. Based on its lower energy density, FFV owners will need to stop to refuel 21% more often when filling up on E85 over E10 (and likewise, 24% more often when refueling on E85 over conventional gasoline).[157] In addition, some FFV owners may be deterred from refueling on E85 out of fear of reduced vehicle performance or just plain unfamiliarity with the new motor vehicle fuel. However, as we move into the future, we believe the biggest determinant will be price – whether E85 is priced competitively with gasoline based on its reduced energy density (discussed in more detail in the subsection that follows).

To comply with the RFS2 program and consume 22.2 billion gallons of ethanol by 2022 (under our primary ethanol control case), not only would we need more FFVs and more E85 retailers, we would need to see a significant increase in the current FFV E85 refueling frequency. Based on the FFV and retail assumptions described above in subsections (b) and (c), our analysis suggests that FFV owners with reasonable access to E85 would need to fill up on it as often as 58% of the time, a significant increase from today's estimated 4% refueling frequency. In order for this to be possible, there will need to be an improvement in the current E85/gasoline price relationship.

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[154] Based on average vehicle miles traveled (VMT) and in-use fuel economy (MPG) for FFVs in the fleet in 2008. For more information on FFV E85 fuel consumption calculations, refer to Section 1.7.4 of the RIA.
[155] EIA, Annual Energy Outlook 2009 - ARRA Update (Table 17).
[156] NEVC, "2008 Purchasing Guide for Flexible Fuel Vehicles." Refers to all mass produced 3.5 and 3.9L Impalas. However, it is our understanding that consumers may still place special orders for non-FFVs.
[157] Based on our assumption that denatured ethanol has an average lower heating value of 77,012 BTU/gal and conventional gasoline (E0) has average lower heating value of 115,000 BTU/gal. For analysis purposes, E10 was assumed to contain 10 vol% ethanol and 90 vol% gasoline. Based on EIA's AEO 2009 assumption, E85 was assumed to contain 74 vol% ethanol and 26 vol% gasoline on average.

e. Market Pricing of E85 Versus Gasoline

According to an online fuel price survey, E85 is currently priced almost 40 cents per gallon or about 15% lower than regular grade conventional gasoline.[158] But this is still about 30 cents per gallon higher than conventional gasoline on an energy-equivalent basis. To increase our nation's E85 refueling frequency to the levels described above, E85 needs to be priced competitively with (if not lower than) conventional gasoline based on its reduced energy content, increased time spent at the pump, and limited availability. Overall, we estimate that E85 would need to be priced about 25% lower than E10 at retail in 2022 in order for it to make sense to consumers.

However, ultimately it comes down to what refiners are willing to pay for ethanol blended as E85. The more ethanol you try to blend as E85, the more devalued ethanol becomes as a gasoline blendstock. Changes to state and Federal excise tax structures could help promote ethanol blending as E85. Similarly, high crude prices make E85 look more attractive. According to EIA's AEO 2009, crude oil prices are expected to increase from about \$80 per barrel (today's price) to \$116/barrel by 2022.[159] Based on our retail cost calculations, ethanol would have to be priced around \$2/gallon or less in order to be attractive to refiners for E85 blending in 2022. According to the DTN Ethanol Center, the current rack price for ethanol is around \$2.20/gallon.[160] However, as explained in Section 4.4 of the RIA, we project that the average ethanol delivered price will come down in the future under the RFS2 program. Therefore, while gasoline refiners and markets will always have a greater profit margin selling ethanol in low-level blends to consumers based on volume, they should be able to maintain a profit selling it as E85 based on energy content in the future.

Once the nation gets past the blend wall, more ethanol will need to be blended as E85 and less as E10. FFV owners who were formerly refueling on gasoline will need to start filling up on E85. Under our primary control case, we expect that 12.9 billion gallons of ethanol would be blended as E10 and 9.3 billion gallons would be blended as E85 to reach the 22.2 billion gallons in 2022. For more on our ethanol consumption feasibility and retail cost calculations, including discussion of the other two control cases, refer to Section 1.7 of the RIA.

3. Consideration of >10% Ethanol Blends

On March 6, 2009, Growth Energy and 54 ethanol manufacturers submitted an application for a waiver of the prohibition of the introduction into commerce of certain fuels and fuel additives set forth in section 211(f) of the Act. This application seeks a waiver for ethanol-gasoline blends of up to 15 percent ethanol by volume.[161] On April 21, 2009, EPA issued a Federal Register notice announcing receipt of the Growth Energy waiver application and

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[158] Based on average E85 and regular unleaded gasoline prices reported at http://www.fuelgaugereport.com/ on November 23, 2009.
[159] EIA, Annual Energy Outlook 2009 – ARRA Update (Table 12).
[160] http://www.dtnethanolcenter.com/index.cfm?show=10&mid=32
[161] http://www.growthenergy.org/2009/e15/Waiver%20Cover%20Letter.pdf. Additional supporting documents are available on the Growth Energy website.

soliciting comment on all aspects of it.[162] On May 20, 2009, EPA issued an additional Federal Register notice extending the public comment period by an additional 60 days.[163] The comment period ended on July 20, 2009, and EPA is now evaluating the waiver application and considering the comments which were submitted.

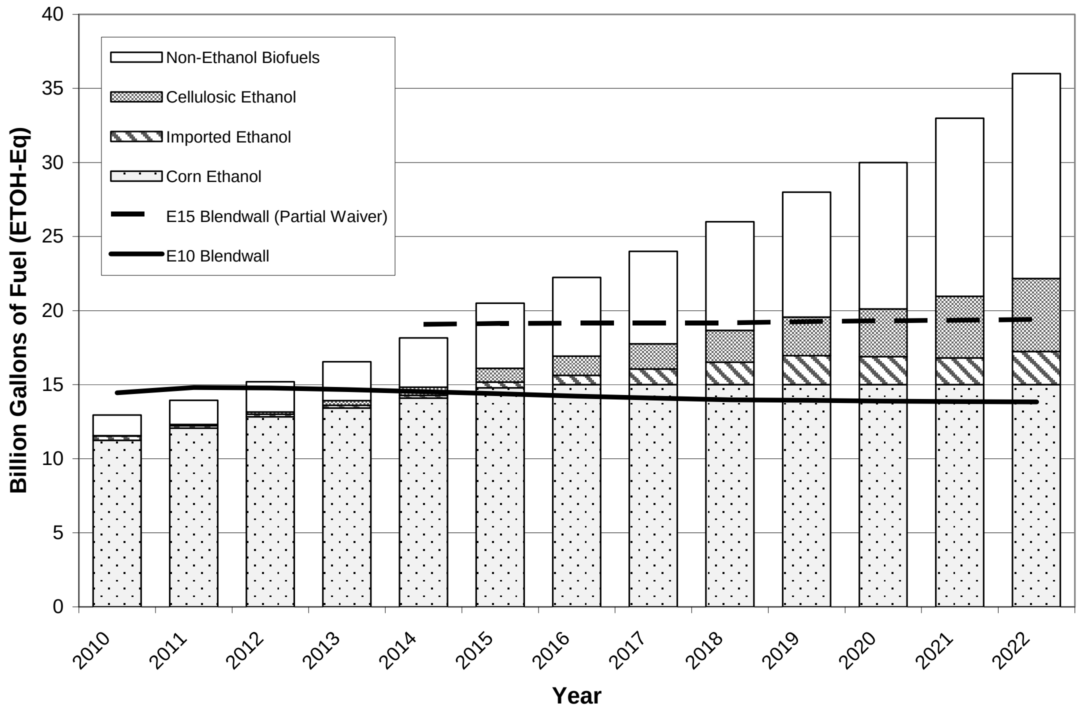
In a letter dated November 30, 2009, EPA notified the applicant that, because crucial vehicle durability information being developed by the Department of Energy would not be available until mid-2010, EPA would be delaying its decision on the application until a sufficient amount of this information could be included in its analysis so that the most scientifically supportable decision could be made.[164] As the current Growth Energy waiver application is still under review, EPA believes it is appropriate to address aspects of the mid-level blend waiver in its decision announcement on the waiver application as opposed to dealing with the comments and evaluation of the potential waiver in the preamble of today's final rule.

Although EPA has yet to make a waiver decision, since its approval could have a significant impact on our analyses that are based on the use of E85, as a sensitivity analysis, we have evaluated the impacts that E15 could have on ethanol consumption feasibility. More specifically, we have assessed the impacts of a partial waiver for newer technology vehicles consistent with the direction of EPA's November 30, 2009 letter. We assumed that E10 would need to continue to co-exist for legacy and non-road equipment based on consumer demand regardless of any waiver decision. For analysis purposes, we assumed E10 would be marketed as premium-grade gasoline (the universal fuel), E15 would be marketed as regular-grade gasoline (to maximize ethanol throughput) and, like today, midgrade would be blended from the two fuels to make a 12.5 vol% blend (E12.5). In addition, we assumed that some E15-capable vehicles would continue to choose E10 or E12.5 based on our knowledge of today's premium and midgrade sales.[165]

In the event of a partial waiver, it is unclear how long it would take for E15 to be fully deployed or whether it would ever be available nationwide. For analysis purposes, we assumed that E15 would be fully phased in and available at all retail stations nationwide by the time the nation hit the blend wall, or around 2014 for our primary control case shown in Figure IV.D.3-1.

[162] Refer to 74 FR 18228 (April 21, 2009).
[163] Refer to 74 FR 23704 (May 20, 2009).
[164] http://www.epa.gov/OMS/regs/fuels/additive/lettertogrowthenergy11-30-09.pdf.
[165] According to EIA's 2008 Petroleum Annual Outlook (Table 45), midgrade and premium comprise 13.5% of total gasoline sales.

Figure IV.D.3-1
Max E15 Ethanol Consumption Compared to Primary Control Case



As modeled, a partial waiver for E15 could increase the ethanol consumption potential from conventional vehicles to about 19 billion gallons. Under our primary control case (shown in Figure IV.D.3-1), E15 could postpone the blend wall by up to five years, or to 2019. Although E15 would fall short of meeting the RFS2 requirements under this scenario, it could provide interim relief while the county ramps up non-ethanol cellulosic biofuel production and expands E85/FFV infrastructure. Under our high-ethanol control case, a partial waiver for E15 could eliminate the need for FFV or E85 infrastructure mandates. Under our low-ethanol control case, E15 could eliminate the need for additional FFV/E85 infrastructure all together. For more information, refer to Section 1.7.6 of the RIA.

V. Lifecycle Analysis of Greenhouse Gas Emissions

A. Introduction

As recognized earlier in this preamble, a significant aspect of the RFS2 program is the requirement that a fuel meet a specific lifecycle greenhouse gas (GHG) emissions threshold for compliance for each of four types of renewable fuels. This section describes the methodology used by EPA to determine the lifecycle GHG emissions of biofuels, and the petroleum-based transportation fuels that they replace. EPA recognizes that this aspect of the RFS2 regulatory program has received particular attention and comment throughout the public comment period. Therefore, this section also will describe the enhancements made to our approach in conducting the lifecycle analysis for the final rule. This section will highlight areas where we have incorporated new scientific data that has become available since the proposal as well as the approach the Agency has taken to recognize and quantify, where appropriate, the uncertainty inherent in this analysis.

1. Open and Science-Based Approach to EPA's Analysis

Throughout the development of EPA's lifecycle analysis, the Agency has employed a collaborative, transparent, and science-based approach. EPA's lifecycle methodology, as developed for the RFS2 proposal, required breaking new scientific ground and using analytical tools in new ways. The work was generally recognized as state of the art and an advance on lifecycle thinking, specifically regarding the indirect impacts of biofuels.

However, the complexity and uncertainty inherent in this work made it extremely important that we seek the advice and input of a broad group of stakeholders. In order to maximize stakeholder outreach opportunities, the comment period for the proposed rule was extended to 120 days. In addition to this formal comment period, EPA made multiple efforts to solicit public and expert feedback on our approach. Beginning early in the NPRM process and continuing throughout the development of this final rule, EPA held hundreds of meetings with stakeholders, including government, academia, industry, and non-profit organizations, to gather expert technical input. Our work was also informed heavily by consultation with other federal agencies. For example, we have relied on the expert advice of USDA and DOE, as well as incorporating the most recent inputs and models provided by these Agencies. Dialogue with the State of California and the European Union on their parallel, on-going efforts in GHG lifecycle analysis also helped inform EPA's methodology. As described below, formal technical exchanges and an independent, formal peer review of the methodology were also significant components of the Agency's outreach. A key result of our outreach effort has been awareness of new studies and data that have been incorporated into our final rule analysis.

Technology Exchanges: Immediately following publication of the proposed rule, EPA held a two-day public workshop focused specifically on lifecycle analysis to assure full understanding of the analyses conducted, the issues addressed, and the options discussed. The workshop featured EPA presentations on each component of the methodology as well as presentations and discussions by stakeholders from the renewable fuel community, federal agencies, universities, and environmental groups. The Agency also took advantage of opportunities to meet in the field with key, affected stakeholders. For example, the Agency was able to twice participate in meetings and tours in Iowa hosted by the local renewable fuel and agricultural community. As described in this section, one of the many outcomes of these meetings was an improved understanding of agricultural and biofuel production practices.

As indicated in the proposal, our lifecycle results were particularly impacted by assumptions about land use patterns and emissions in Brazil. During the public comment process we were able to update and refine these assumptions, including the incorporation of new, improved sources of data based on Brazil-specific data and programs. In addition, the Agency received more recent trends on Brazilian crop productivity, areas of crop expansion, and regional differences in costs of crop production and land availability. Lastly, we received new information on efforts to curb deforestation allowing the Agency to better predict this impact through 2022.

Peer Review: To ensure the Agency made its decisions for this final rule on the best science available, EPA conducted a formal, independent peer review of key components of the analysis. The reviews were conducted following the Office of Management and Budget's peer review guidance that ensures consistent, independent government-wide implementation of peer review, and according to EPA's longstanding and rigorous peer review policies. In accordance with these guidelines, EPA used independent, third-party contractors to select highly qualified peer reviewers. The reviewers selected are leading experts in their respective fields, including lifecycle assessment, economic modeling, remote sensing imagery, biofuel technologies, soil science, agricultural economics, and climate science. They were asked to evaluate four key components of EPA's methodology: (1) land use modeling, specifically the use of satellite data and EPA's proposed land conversion GHG emission factors; (2) methods to account for the variable timing of GHG emissions; (3) GHG emissions from foreign crop production (both the modeling and data used); and (4) how the models EPA relied upon are used together to provide overall lifecycle estimates.

The advice and information received through this peer review are reflected throughout this section. EPA's use of higher resolution satellite data is one example of a direct outcome of the peer review, as is the Agency's decision to retain its reliance upon this data. The reviewers also provided recommendations that have helped to inform the larger methodological decisions presented in this final rule. For example, the reviewers in general supported the importance of assessing indirect land use change and determined that EPA used the best available tools and approaches for this work. However, the review also recognized that no existing model comprehensively simulates the direct and indirect effects of biofuel production both domestically and internationally, and therefore model development is still evolving. The uncertainty associated with estimating indirect impacts and the difficulty in developing precise results also were reflected in the comments. In the long term, this peer review will help focus EPA's ongoing lifecycle analysis work as well as our future interactions with the National Academy of Science and other experts.

Altogether, the many and extensive public comments we received to the rule docket, the numerous meetings, workshops and technical exchanges, and the scientific peer review have all been instrumental to EPA's ability to advance our analysis between proposal and final and to develop the methodological and regulatory approach described in this section.

2. Addressing Uncertainty

The peer review, the public comments we have received, and the analysis conducted for the proposal and updated here for the final rule, indicate that it is important to take into account indirect emissions when looking at lifecycle emissions from biofuels. It is clear that, especially when considering commodity feedstocks, including the market interactions of biofuel demand on feedstock and agricultural markets is a more accurate representation of the impacts of an increase in biofuels production on GHG emissions than if these market interactions are not considered.

However, it is also clear that there are significant uncertainties associated with these estimates, particularly with regard to indirect land use change and the use of economic models to project future market interactions. Reviewers highlighted the uncertainty associated with our lifecycle GHG analysis and pointed to the inherent uncertainty of the economic modeling.

In the proposal, we asked for comment on whether and how to conduct an uncertainty analysis to help quantify the magnitude of this uncertainty and its relative impact on the resulting lifecycle emissions estimates. The results of the peer review, and the feedback we have received from the comment process, supported the value of conducting such an analysis. Therefore, working closely with other government agencies as well as incorporating feedback from experts who commented on the rule, we have quantified the uncertainty associated specifically with the international indirect land use change emissions associated with increased biofuel production.

Although there is uncertainty in all portions of the lifecycle modeling, we focused our uncertainty analysis on the factors that are the most uncertain and have the biggest impact on the results. For example, the energy and GHG emissions used by a natural gas-fired ethanol plant to produce one gallon of ethanol can be calculated through direct observations, though this will vary somewhat between individual facilities. The indirect domestic emissions are also fairly well understood, however these results are sensitive to a number of key assumptions (e.g., current and future corn yields). The indirect, international emissions are the component of our analysis with the highest level of uncertainty. For example, identifying what type of land is converted internationally and the emissions associated with this land conversion are critical issues that have a large impact on the GHG emissions estimates.

Therefore, we focused our efforts on the international indirect land use change emissions and worked to manage the uncertainty around those impacts in three ways: (1) getting the best information possible and updating our analysis to narrow the uncertainty, (2) performing sensitivity analysis around key factors to test the impact on the results, and (3) establishing reasonable ranges of uncertainty and using probability distributions within these ranges in threshold assessment. The following sections outline how we have incorporated these three approaches into our analysis.

EPA recognizes that as the state of scientific knowledge continues to evolve in this area, the lifecycle GHG assessments for a variety of fuel pathways will continue to change.

Therefore, while EPA is using its current lifecycle assessments to inform the regulatory determinations for fuel pathways in this final rule, as required by the statute, the Agency is also committing to further reassess these determinations and lifecycle estimates. As part of this ongoing effort, we will ask for the expert advice of the National Academy of Sciences, as well as other experts, and incorporate their advice and any updated information we receive into a new assessment of the lifecycle GHG emissions performance of the biofuels being evaluated in this final rule. EPA will request that the National Academy of Sciences over the next two years evaluate the approach taken in this rule, the underlying science of lifecycle assessment, and in particular indirect land use change, and make recommendations for subsequent rulemakings on this subject. This new assessment could result in new determinations of threshold compliance compared to those included in this rule that would apply to future production (from plants that are constructed after each subsequent rule).

B. Methodology

The regulatory purpose of this analysis is to determine which biofuels (both domestic and imported) qualify for the four different GHG reduction thresholds and renewable fuel categories established in EISA (see Section I.A). This threshold assessment compares the lifecycle emissions of a particular biofuel against the lifecycle emissions of the petroleum-based fuel it is replacing (e.g., ethanol replacing gasoline or biodiesel replacing diesel). This section discusses the Agency's approach both for assessing the lifecycle GHG emissions from biofuels as well as for the petroleum-based fuels replaced by the biofuels.

As described in detail below, EPA has received a number of comments on the different pieces of this analysis and has thoroughly considered those comments as well as feedback from our peer review process. In each section below we will discuss comments received and how they impacted our analysis.

1. Scope of Analysis

As stated in the proposal, the definition of lifecycle GHG emissions established by Congress in EISA is critical to establishing the scope of our analysis. Congress specified that:

> The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[166]

This definition forms the basis of defining the goal and scope of our lifecycle GHG analysis and in determining to what extent changes should be made to the analytical approach outlined in our proposed rulemaking.

[166] Clean Air Act Section 211(o)(1).

a. Inclusion of Indirect Land Use Change

EPA notes that it received significant comment on including international indirect emissions in its lifecycle calculations. Most of the comments suggested that the science of international indirect land use change was too new, or that the uncertainty involved was too great, to be included in a regulatory analysis. EPA continues to believe that compliance with the EISA mandate — determining “the aggregate GHG emissions related to the full fuel lifecycle, including both direct emissions and significant indirect emissions such as land use changes” — makes it necessary to assess those direct and significant indirect impacts that occur not just within the United States, but also those that occur in other countries.

Some commenters strongly supported EPA’s proposal to include significant GHG emissions that occur overseas and are related to the lifecycle of renewable fuels or baseline fuels used in the United States. These commenters agreed that the text of the statute supports EPA’s proposed approach, and that the alternative of ignoring such emissions would result in grossly inaccurate assessments, and would be inconsistent with the international nature of GHG pollution and the fact that overseas emissions have domestic impacts.

Other commenters argued that the presumption against extraterritorial application of domestic laws carries with it the presumption that Congress is concerned with domestic effects and domestic impacts only. They assert further that Congress intended to benefit domestic agriculture through EISA enactment, and that the statute’s ambiguous terms should not be interpreted in a manner that could harm domestic agriculture in general or, for one commenter, the biodiesel industry in particular. Although considering international emissions in its analyses could result in different implications under the statute for various fuels and fuel pathways as compared to ignoring these emissions, EPA believes that this is precisely the outcome that Congress intended. Implementation of EISA will undoubtedly benefit the domestic agricultural sector as a whole, with some components benefiting more than others depending in part on the lifecycle GHG emissions associated with the products to be made from individual feedstocks. If Congress had sought to promote all biofuel production without regard to GHG emissions related to the full lifecycle of those fuels, it would not have specified GHG reduction thresholds for each category of renewable fuel for which volume targets are specified in the Act.

It is also important to note that including international indirect emissions in EPA’s lifecycle analysis does not exercise regulatory authority over activities that occur solely outside the U.S., nor does it raise questions of extra-territorial jurisdiction. EPA’s regulatory action involves an assessment of products either produced in the U.S. or imported into the U.S. EPA is simply assessing whether the use of these products in the U.S. satisfies requirements under EISA for the use of designated volumes of renewable fuel, cellulosic biofuel, biomass-based diesel, and advanced biofuel. Considering international emissions in determining the lifecycle GHG emissions of the domestically-produced or imported fuel does not change the fact that the actual regulation of the product involves its use solely inside the U.S.

A number of commenters pointed to the text and structure of the definition of “lifecycle greenhouse gas emissions” to argue that EPA either is not authorized to consider GHG emissions related to international land use change, or that it is not required to do so. One commenter suggested that the reference in the definition of “lifecycle greenhouse gas emissions” to “all stages” of the lifecycle “from” feedstock generation “through” use of the fuel by the ultimate consumer does not include indirect emissions that result from decisions to place more land in acreage overseas for such non-fuel purposes as cattle feed. Another commenter stated that EPA’s approach does not give any meaning to the terms “significant” and “fuel lifecycle” in the definition, but instead focuses on the words such as “full” to arrive at an expansive meaning. This commenter also noted the lack of any specific reference to international considerations in Section 211(o), as opposed to other provisions in the CAA, such as Section 115.

EPA believes that a complete analysis of the aggregate GHG emissions related to the full lifecycle of renewable fuels includes the significant indirect emissions from international land use change that are predicted to result from increased domestic use of agricultural feedstocks to produce renewable fuel. The statute specifically directs EPA to include in its analyses significant indirect emissions such as significant emissions from land use changes. EPA has not ignored either the terms “significant” or “life cycle.” It is clear from EPA’s assessments that the modeled indirect emissions from land use changes are “significant” in terms of their relationship to total GHG emissions for given fuel pathways. Therefore, they are appropriately considered in the total GHG emissions profile for the fuels in question. EPA has not ignored the term “life cycle.” The entire approach used by EPA is directed to fully analyzing emissions related to the complete lifecycle of renewable and baseline fuels.

Although the definition of lifecycle greenhouse gas emissions in Section 211(o) does not specifically mention international emissions, it would be inconsistent with the intent of this section of the amended Act to exclude them. A large variety of activities outside the U.S. play a major part in the full fuel lifecycle of both baseline (gasoline and diesel fuel used as transportation fuel in 2005) and renewable fuels. For example, several stages of the lifecycle process for gasoline and diesel can occur overseas, including extraction and delivery of imported crude oil, and for imported gasoline and diesel products, emissions associated with refining and distribution of the finished product to the U.S. For imported renewable fuel, all of the emissions associated with feedstock production and distribution, fuel processing, and delivery of the finished renewable fuel to the U.S. occur overseas. The definition of lifecycle GHG emissions makes it clear that EPA is to determine the aggregate emissions related to the “full” fuel lifecycle, including “all stages of fuel and feedstock production and distribution.” Thus, EPA could not, as a legal matter, ignore those parts of a fuel lifecycle that occur overseas.

Drawing a distinction between GHG emissions that occur inside the U.S. as compared to emissions that occur outside the U.S. would result in a lifecycle analysis that bears no apparent relationship to the purpose of this provision. The purpose of the thresholds in EISA is to require the use of renewable fuels that achieve reductions in GHG emissions compared to the baseline. Ignoring international emissions, a large part of the GHG emission associated with the different fuels, would result in a GHG analysis that bears no relationship to the real world emissions impact of transportation fuels. The baseline would be significantly understated, given the large amount of imported crude and imported finished gasoline and diesel used in 2005. Likewise, the emissions estimates for imported renewable fuel would be grossly reduced in comparison to the aggregate emissions estimates for fuels made domestically with domestically-grown feedstocks, simply because the impacts of domestically produced fuels occurred within the U.S. EPA does not believe that Congress intended such a result.

Excluding international impacts means large percentages of GHG emissions would be ignored. This would take place in a context where the global warming impact of emissions is irrespective of where the emissions occur. If the purpose of thresholds is to achieve some reduction in GHG emissions in order to help address climate change, then ignoring emissions outside our borders interferes with the ability to achieve this objective. Such an approach would essentially undermine the purpose of the provision, and would be an arbitrary interpretation of the broadly phrased text used by Congress.

One commenter stated that matters that could appropriately be considered part of a food lifecycle (new land clearing for overseas grain production as a result of decreased US grain exports) should not be considered part of a renewable fuel lifecycle. However, the suggested approach would mean that EPA would fail to account for the significant indirect emissions that relate to renewable fuel production. EPA believes this would be counter to Congressional intent. Although a life cycle analysis of foreign food production may also take into account a given land use change, that does not mean that the same land use change should not be considered in evaluating its ultimate cause, which may be renewable fuel production in the United States.

Some comments asserted that significant GHG gas emissions from international land use change should not be considered if the only available models for doing so are not generally accepted or valid considering economics or science, or where the approach is new and untested, or where the data are faulty and EPA models unrealistic scenarios. As described in this rulemaking, EPA has used the best available models and substantially modified key inputs to those models to reflect comments by peer reviewers, the public, and emerging science. EPA has also modeled additional scenarios from those described in the NPRM. EPA recognizes that uncertainty exists with respect to the results, and has attempted to quantify the range of uncertainty. While EPA agrees that application of the models it has used in the context of assessing GHG emissions represents changes from previous biofuel lifecycle modeling, EPA disagrees that it has used faulty data, modeled unrealistic scenarios, or that its approach is otherwise scientifically indefensible. Although the results of modeling GHG emissions associated with international land use change are uncertain, EPA has attempted to quantify that uncertainty and is now in a better position to consider the uncertainty inherent in its approach.

One commenter asserted that by considering international land use changes, EPA is seeking to penalize domestic renewable fuel producers for impacts over which they have no control. In response, EPA disagrees that it is seeking to penalize anyone at all. EPA is simply attempting to account for all GHG emissions related to the full fuel lifecycle. Domestic renewable fuel producers may have no direct control over land use changes that occur overseas as a result of renewable fuel production and use here, but their choice of feedstock can and does influence oversees activities, and EPA believes it is appropriate to consider the GHG emissions from those activities in its analyses.

Some commenters noted that a finding of causation is built into the definitions of "indirect effects" in the Endangered Species Act and the National Environmental Policy Act, and that EPA should interpret the reference to "indirect emissions' in EISA as requiring similar findings of causation. Specifically, they argue that for EPA to count GHG emissions from international land use change in its assessments, EPA must find that renewable fuel production "caused" the land use change. In response, without addressing the commenter's claims regarding the requirements of NEPA or the ESA, EPA notes that Congress has specified in Section 211(o) the required causal link between a fuel and indirect emissions. The indirect emissions must be "related to" the full fuel lifecycle. EPA believes that it has demonstrated this link through its modeling efforts. Specifically, the models predict that increased demand for feedstocks to produce renewable fuel that satisfies EISA mandates will likely result in international land use change. Such change is, then, "related to" the full fuel lifecycle of these fuels. EPA does not believe that the statute requires EPA to wait until these effects occur to establish the required linkage, but instead believes that it is authorized to use predictive models to demonstrate likely results.

The term "related to" is generally interpreted broadly as meaning to have a connection to or refer to a matter. To determine whether an indirect emission has the appropriate connection to the full fuel lifecycle, we must look at both the objectives of this provision as well as the nature of the relationship. EPA has used a suite of global models to project a variety of agricultural impacts of the RFS program, including changes in the types of crops and number of acres planted world-wide. These shifts in the agricultural market are a direct consequence of the increased demand for biofuels in the U.S. This increased demand diverts biofuel feedstocks from other competing uses, and also increases the price of the feedstock, thus spurring additional international production. Our analysis uses country-specific information to determine the amount, location, and type of land use change that would occur to meet these changes in production patterns. The linkages of these changes to increased U.S. biofuel demand in our analysis are generally close, and are not extended or overly complex.

Overall, EPA is confident that it is appropriate to consider indirect emissions, including those from both domestic and international land use changes, as "related to" the full fuel lifecycle, based on the results of our modeling. These results form a reasonable technical basis for the linkage between the full fuel lifecycle of transportation fuels and indirect emissions, as well as for the determination that these emissions are significant. EPA believes that while uncertainty in the resulting aggregate GHG estimates should be taken into consideration, it would be inappropriate to exclude indirect emissions estimates from this analysis. The use of reasonable estimates of these kinds of indirect emissions allows EPA to conduct a reasoned evaluation of total GHG impacts, which is needed to promote the objectives of this provision, as compared to ignoring or not accounting for these indirect emissions.

EPA understands that including international indirect land use change is a key decision and that there is significant uncertainty associated with it. That is why we have taken an approach that quantifies that uncertainty and presents the weight of currently available evidence in making our threshold determinations.

b. Models Used

As described in the proposal, to estimate lifecycle indirect impacts of biofuel production requires the use of economic modeling to determine the market impacts of using agricultural commodity feedstocks for biofuels. The use of economic models and the uncertainty of those models to accurately predict future agricultural sector scenarios was one of the main comments we received on our analysis. While the comments and specifically the peer review supported our need to use economic models to incorporate and measure indirect impacts of biofuel production, they also highlighted the uncertainty with that modeling approach, especially in projecting out to the future.

However, it is important to note that while there are many factors that impact the uncertainty in predicting total land used for crop production, making accurate predictions of many of these factors are not relevant to our analysis. For example different assumptions about economic growth rates, weather, and exchange rates will all impact future agricultural projections including amount of land use for crops. However, we are interested only in the difference between two biofuel scenarios holding all other changes constant. So the absolute values and projections for crops and other variables in the model projections are not as important as the difference the model is projecting due to an increase in biofuels production. This limits the uncertainty of using the economic models for our analysis.

Furthermore, one of the key uncertainties associated with our agricultural sector economic modeling that has the biggest impact on land use change results is the assumptions around crop yields. As discussed in Section V.A.2, we are conducting sensitivity analysis around different yield assumptions in our analysis.

Therefore, because of the fact that we are only using the economic models to determine the difference between two projected scenarios and the fact that we are conducting sensitivity analysis around the yield assumptions we feel it is appropriate and acceptable to use economic models in our analysis of determining GHG thresholds in our final rule analysis.

As was the case in the proposed analysis, to estimate the changes in the domestic agricultural sector (e.g., changes in crop acres resulting from increased demand for biofuel feedstock or changes in the number of livestock due to higher corn prices) and their associated emissions, EPA uses the Forestry and Agricultural Sector Optimization Model (FASOM), developed by Texas A&M University and others. To estimate the impacts of biofuels feedstock production on international agricultural and livestock production, we used the integrated Food and Agricultural Policy and Research Institute international models, as maintained by the Center for Agricultural and Rural Development (FAPRI-CARD) at Iowa State University.

One of the main comments we received on our choice of models was the issue of transparency. Several comments were concerned that the results of EPA's modeling efforts can not be duplicated outside the experts who developed the models and conducted the analysis used by EPA in the proposal. Upon the release of the proposal, EPA requested comment on the use of these various models. EPA conducted a number of measures to gather comments, including the public comment period upon release of the NPRM analysis, holding a public workshop on the lifecycle methodology, and conducting a peer review of the lifecycle methodology. Specifically, one of the major tasks of the peer review of EPA's lifecycle GHG methodology was to review and comment on the use of the various models and their linkages. The response we received through the peer review is supportive of our use of the FASOM and FAPRI-CARD models, affirming that they are the strong and appropriate tools for the task of estimating land use changes stemming from agricultural economic impacts due to changes in biofuel policy.

In addition, in an effort to garner as useful comments as possible and to be as transparent as possible about the modeling process, EPA supplied in the docket technical documents for the FASOM and FAPRI-CARD models, the output received by EPA from each model, and the models themselves such that the public and commenters could learn and examine how each model operates.

Building upon the support for the use of the FASOM and FAPRI-CARD models, a number of important enhancements were made to both models in response to comments received through the public comment system and through the peer review, and in consultation with various experts on domestic and international agronomics. These enhancements include updated substitution rates of corn and soybean meal for distillers grains (DG) based on recent scientific research by Argonne National Laboratory, the addition of a corn oil from the dry mill ethanol extraction process as a source of biodiesel, the full incorporation of FASOM's forestry model that dynamically interacts with the agriculture sector model in the U.S., as well as the addition of a Brazil regional model to the FAPRI-CARD modeling system. All of these enhancements are discussed in more detail below and in the RIA (Chapter 2 and 5). In addition to the model enhancements we also conducted a sensitivity analysis on yields as part of our final rule analysis. These updates to our modeling and the sensitivity analysis was done in response to public comments specifically asking for this to add transparency to the modeling and modeling results.

We also received comments on the combined use of FASOM and FAPRI-CARD. Several comments and peer reviewers questioned the benefit of using two agricultural sector models. Specifically reviewers pointed to some of the inconsistencies in the FASOM and FAPRI-CARD domestic results. For the final rule analysis we worked to reconcile the two model results. We apply the same set of scenarios and key input assumptions in both models. For example, both models were updated to apply consistent treatment of DGs in domestic livestock feed replacement and consistent assumptions regarding DG export.

Some reviewers questioned the benefits of using FASOM and suggested we rely entirely on the FAPRI-CARD model for the analysis. However, we continue to believe there are benefits to the use of FASOM. Specifically, the fact that FASOM has domestic land use change interactions between crop, pasture, and forest integrated into the modeling is an advantage over using the domestic FAPRI-CARD model that only tracks cropland.

c. Scenarios Modeled

As was done for the proposal, to quantify the lifecycle GHG emissions associated with the increase in renewable fuel mandated by EISA, we compared the differences in total GHG emissions between two future volume scenarios in our economic models. For each individual biofuel, we analyzed the incremental GHG emission impacts of increasing the volume of that fuel to the total mix of biofuels needed to meet the EISA requirements. Rather than focus on the impacts associated with a specific gallon of fuel and tracking inputs and outputs across different lifecycle stages, we determined the overall aggregate impacts across sectors of the economy in response to a given volume change in the amount of biofuel produced.

Volum______e Scenarios: The two future scenarios considered included a "business as usual" volume of a particular renewable fuel based on what would likely be in the fuel pool in 2022 without EISA, as predicted by the Energy Information Agency's Annual Energy Outlook (AEO) for 2007 (which took into account the economic and policy factors in existence in 2007 before EISA). The second scenario assumed a higher volume of renewable fuels as mandated by EISA for 2022.

We project our analysis and economic modeling through the life of the program. We then consider the impacts of an increase of biofuels on the agricultural sector in 2022 as the basis for our threshold analysis. This was an area that we received numerous comments on highlighting that this approach adds uncertainty to our results because we are projecting uncertain technology and other changes out into the future. One of the recommendations was to base the lifecycle GHG assessments on a near term time frame and update the analysis every few years to capture actual technology changes.

We continue to focus our final rule analyses on 2022 results for two main reasons. First, it would require an extremely complex assessment and administratively difficult implementation program to track how biofuel production might continuously change from month to month or year to year. Instead, it seems appropriate that each biofuel be assessed a level of GHG performance that is constant over the implementation of this rule, allowing fuel providers to anticipate how these GHG performance assessments should affect their production plans. Second, it is appropriate to focus on 2022, the final year of ramp up in the required volumes of renewable fuel as this year. Assessment in this year allows the complete fuel volumes specified in EISA to be incorporated. This also allows for the complete implementation of technology changes and updates that were made to improve or modeling efforts. For example, the inclusion of price induced yield increases and the efficiency gains of DGs replacement are phased in over time. Furthermore, these changes are in part driven by the changes in earlier years of increased biofuel use.

Crop Yield Scenarios: EPA received numerous comments to the effect that we should consider a case in our economic models with higher yields that what were projected for the proposed rule analysis. There are many factors that go into the economic modeling but the yield assumptions for different crops has one of the biggest impacts on land use and land use change. Therefore, for this analysis we ran a base yield case and a high yield case. This will provide two distinct model results for key parameters like total amount of land converted by crop by country.

EPA's base yield projections are derived from extrapolating through 2022 long-term historical U.S. corn yields from 1985 to 2009. This estimate, 183 bushels/acre for corn and 48 bushels/acre for soybeans, is consistent with USDA's method of projecting future crop yields. During the public comment process we learned that numerous technical advancements--including better farm practices, seed hybridization and genetic modification--have led to more rapid gains in yields since 1995. In addition, commenters, including many leading seed companies, provided data supporting more rapid improvements in future yields. For example, commenters pointed to recent advancements in seed development (including genetic modification) and the general accumulation of knowledge of how to develop and bring to market seed varieties—factors that would allow for a greater rate of development of seed varieties requiring fewer inputs such as fertilizer and pest management applications. This new information would suggest that the base yield may be a conservative estimate of future yields in the U.S. Therefore, in coordination with USDA experts, EPA has developed for this final rule a high yield case scenario of 230 bushels/acre for corn and 60 bushels/acre for soybeans. These figures represent the 99% upper bound confidence limit of variability in historical U.S. yields. This high yield case represents a feasible high yield scenario for the purpose of a sensitivity test of the impact on the results of higher yields.

Feedback we received indicated that corn and soybean yields respond in tandem and that a high yield corn case would also imply a higher yield for soybeans as well. The high yield case is therefore based on higher yield corn and soybeans in the U.S. as well as in the major corn and soybean producing countries around the world. For international yields, it is reasonable to assume the same percent increases from the baseline yield assumptions could occur as we are estimating for the U.S. Thus in the case of corn, 230 bushels per acre is approximately 25% higher than the U.S. baseline yield of 183 bushels per acre in 2022. This same 25% increase in yield can be expected for the top corn producers in the rest of the world by 2022, as justified improvements in seed varieties and, perhaps even more so than in the case of the U.S., improvements in farming practices which can take more full advantage of the seed varieties' potential. For example, seeds can be more readily developed to perform well in the particular regions of these countries and can be coupled with much improved farming practices as farmers move away from historical practices such as saving seeds from their crop for use the next year and better understand the economic advantages of modern farming practices. So the high yield scenarios would not have the same absolute yield values in other countries as the U.S. but would have the same percent increase.

While we modeled a high yield scenario for this analysis we continue to rely primarily on the base yield estimates in our assessments of different biofuel lifecycle GHG emissions recognizing that the base yields could be conservative. The reasons outlined above could lead to higher rates of yield growth in the future, however, there are mitigating factors that could limit this yield growth or potentially cause reductions in yield growth rates. For example, the water requirements for both increased corn farming and ethanol production could lead to future water constraints that may in some regions limit yield growth potential. Furthermore, one of the long term impacts of potential global climate change could be a reduction in agricultural output of different impacted regions around the world, including the U.S. This could also serve to reduce yield growth. As with many aspects of this lifecycle modeling, as the science and data evolves on crop yields, the Agency will update its factors accordingly.

2. Biofuel Modeling Framework & Methodology for Lifecycle Analysis Components

As discussed above, to account for the direct and indirect emissions of biofuel production required the use of agricultural sector economic models. The results of these models were combined with other data sources to generate lifecycle GHG emissions for the different fuels. The basic modeling framework involved the following steps and modeling tools.

To estimate the changes in the domestic agricultural sector we used FASOM, developed by Texas A&M University and others. FASOM is a partial equilibrium economic model of the U.S. forest and agricultural sectors that tracks over 2,000 production possibilities for field crops, livestock, and biofuels for private lands in the contiguous United States. Because FASOM captures the impacts of all crop production, not just biofuel feedstock, we are able to use it to determine secondary agricultural sector impacts, such as crop shifting and reduced demand due to higher prices.

The output of the FASOM analysis includes changes in total domestic agricultural sector fertilizer and energy use. These are calculated based on the inputs required for all the different crops modeled and changes in the amounts of the different crops produced due to increased biofuel production. FASOM output also includes changes in the number and type of livestock produced. These changes are due to the changes in animal feed prices and make-up due to the increase in biofuel production. The FASOM output changes in fertilizer, energy use, and livestock are combined with GHG emission factors from those sources to generate biofuel lifecycle impacts. The GHG emission factors for fuel and fertilizer production come from the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) spreadsheet analysis tool developed by Argonne National Laboratories, and livestock GHG emission factors are from IPCC guidance.

To estimate the domestic impacts of N_2O emissions from fertilizer application, we used the DAYCENT model developed by Colorado State University. The DAYCENT model simulates plant-soil systems and is capable of simulating detailed daily soil water and temperature dynamics and trace gas fluxes (CH_4, N_2O, and NO_x). DAYCENT model results for N_2O emissions from different crop and land use changes were combined with FASOM output to generate overall domestic N_2O emissions.

FASOM output also provides changes in total land use required for agriculture and land use shifting between crops, and interactions with pasture, and forestry. This output is combined with emission factors from land use change to generate domestic land use change GHG emissions from increased biofuel production.

To estimate the impacts of biofuels feedstock production on international agricultural and livestock production, we used the integrated FAPRI-CARD international models, developed by Iowa State University. These worldwide agricultural sector economic models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities.

The output of the FAPRI-CARD model included changes in crop acres and livestock production by type by country globally. Unlike FASOM, the FAPRI-CARD output did not include changes in fertilizer or energy use or have land type interactions built in. These were developed outside the FAPRI-CARD model and combined with the FAPRI-CARD output to generate GHG emission impacts.

Crop input data by crop and country was developed and combined with the FAPRI-CARD output crop acreage change data to generate overall changes in fertilizer and energy use. These fertilizer and energy changes along with the FAPRI-CARD output livestock changes were then converted to GHG emissions based on the same basic approach used for domestic sources, which involves combining with emission factors from GREET and IPCC.

International land use change emissions were determined based on combining FAPRI-CARD output of crop acreage change with satellite data to determine types of land impacted by the projected crop changes and then applying emission factors of different land use conversions to generate GHG impacts.

Additional modeling and data sources used to determine the GHG emissions of other stages in the biofuel lifecycle include studies and data on the distance and modes of transport needed to ship feedstock from the field to the biofuel processing facility and the finished biofuel from the facility to end use. These distances and modes are used to develop amount and type of energy used for transport which is combined with GREET factors to generate GHG emissions. We also calculate energy use needed in the biofuel processing facility from industry sources, reports, and process modeling. This energy use is combined with emissions factors from GREET to develop GHG impacts of the biofuel production process

The following sections outline how the modeling tools and methodology discussed above were used in conducting the analysis for the different lifecycle stages of biofuel production, including changes made since the proposal. Lifecycle stages discussed include feedstock production, land use change, feedstock and fuel transport, biofuel production, and vehicle end use. The modeling of the petroleum fuels baseline is discussed in Section V.B.3.

a. Feedstock Production

Our analysis addresses the lifecycle GHG emissions from feedstock production by capturing both the direct and indirect impacts of growing corn, soybeans, and other renewable fuel feedstocks. For both domestic and international agricultural feedstock production, we analyzed four main sources of GHG emissions: agricultural inputs (e.g., fertilizer and energy use), fertilizer N_2O, livestock, and rice methane. (Emissions related to land use change are discussed in the next section).

i. *Domestic Agricultural Sector Impacts*

Agricultural Sector Inputs: The proposal analysis calculated GHG emissions from domestic agriculture fertilizer and energy use and production change by applying rates of energy and fertilizer use by crop by region to the FASOM acreage data and then multiplying by default factors for GHG emissions from GREET. Fuel use emissions from GREET include both the upstream emissions associated with production of the fuel and downstream combustion emissions.

In general commenters supported this approach as it captures all indirect impacts of agricultural sector emissions and not just those associated with the specific biofuel crop in question. However, we did receive comments as part of our Model Linkages Peer Review that the input data for some crops may be overestimating GHG emissions. Specifically, the commenter highlighted that N_2O emissions from domestic hay production seemed to be over estimated. As part of the final rule analysis EPA confirmed that input data was being used correctly, however, the hay N_2O emissions in the proposal may have been overestimated based on the approach used in the proposal to generate N_2O emissions from nitrogen fixing crops. This has been updated for the final rule analysis as discussed in the next section which resulted in lower emissions from nitrogen fixing crops.

Other comments indicated that we should be using the most up to date data for our calculations of GHG emissions. Since the proposal there has been a new release of the GREET model (Version 1.8C). EPA reviewed the new version and concluded that this was an improvement over the previous GREET release that was used in the proposal analysis (Version 1.8B). Therefore, EPA updated the GHG emission factors for fertilizer production used in our analysis to the values from the new GREET version. This had the result of slightly increasing the GHG emissions associated with fertilizer production and thus slightly increasing the GHG emission impacts of domestic agriculture.

As was the case in the proposal, we held the rates of domestic fertilizer application constant over time. This is true for both of our yield scenarios considered as well as for price induced yield increases. This constant rate of application is justified based on USDA data indicating that crops are becoming more efficient in their uptake of fertilizer such that higher yields can be achieved based on the same per acre fertilizer application rates.

<u>N_2O Emissions</u>: The proposal analysis calculated N_2O emissions from domestic fertilizer application and nitrogen fixing crops based on the amount of fertilizer used and different regional factors to represent the percent of nitrogen (N) fertilizer applied that result in N_2O emissions. The proposal analysis N_2O factors were based on existing DAYCENT modeling that was developed using the 1996 IPCC guidance for calculating N_2O emissions from fertilizer applications and nitrogen fixing crops. We identified in the proposal that this was an area we would be updating for the final rule based on new analysis from Colorado State University using the DAYCENT model. This update was not available at time of proposal.

We received a number of comments on our proposal results indicating that the N_2O emissions were overestimated from soybean and other legume production (e.g., nitrogen fixing hay) in our analysis. The main issue is that because the N_2O emission factors used in the proposal were based on the 1996 IPCC guidance for N_2O accounting they were overestimating N_2O emissions from nitrogen fixing crops. As an update in 2006, IPCC guidance was changed such that biological nitrogen fixation was removed as a direct source of N_2O because of the lack of evidence of significant emissions arising from the fixation process itself. IPCC concluded that the N_2O emissions induced by the growth of legume crops/forages may be estimated solely as a function of the above-ground and below-ground nitrogen inputs from crop/forage residue. This change effectively reduces the N_2O emissions from nitrogen fixing crops like soybeans and nitrogen fixing hay from the 1996 to 2006 IPCC guidance.

Therefore, as part of the update to new N_2O emission factors from DAYCENT used for our final rule analysis we have updated to the 2006 IPCC guidance which reduces the N_2O emissions from soybean production. This has the effect of reducing lifecycle GHG emissions for soybean biodiesel production. When we model corn expansion as would result from increased production of corn-based ethanol, one of the impacts is that the increase in corn acres displaces some acres otherwise planted to soy beans. Since the GHG emissions impact of this change in land use considers the N_2O emissions benefit from the displaced soy, the result of this lower soy bean N_2O assessment means that the benefits for soy displacement are less, directionally increasing the net GHG emissions for corn expansion.

We also received comments on our approach that we should use IPCC factors directly as opposed to relying on DAYCENT modeling. The difference is that IPCC provides default factors by crop by country, while DAYCENT models N_2O emissions by crop but also by region within the US, accounting for different soil types and weather factors. For the final rule we still rely on the DAYCENT modeling results as we believe them to be more accurate. For example, the National Greenhouse Gas Inventory as reported annually by the US to the Framework Convention on Climate Change uses the DAYCENT model to determine N_2O emissions from domestic fertilizer use as opposed to using default IPCC factors as the DAYCENT modeling is recognized to be a more accurate approach.

<u>Livestock Emissions</u>: GHG emissions from livestock have two main sources: enteric fermentation and manure management. For the proposal, enteric fermentation methane emissions were determined by applying IPCC default factors for different livestock types to herd values as calculated by FASOM to get GHG emissions. Comments we received on this approach were that the default IPCC factors do not account for the beneficial use of distiller grains (DGs) as animal feed. Use of DGs has been shown to decrease methane produced from enteric fermentation if replacing corn as animal feed. This is due to the fact that the DGs are a more efficient feed source. Consistent with our assumptions regarding the efficiency of DGs as an animal feed in our agricultural sector modeling, we have also included the enteric fermentation methane reductions of DGs use in our final rule analysis. The reduction amount was based on default factors in GREET that calculated this reduction based on the same Argonne report used to determine DGs feed replacement efficiency discussed in Section V.B.2.b.i. This resulted in a reduction in the lifecycle GHG emissions for corn ethanol compared to the proposal assumptions. More detail on the enteric fermentation methane reductions of DGs use can be found in Chapter 2 of the RIA.

The proposal analysis also included the methane and N_2O emissions of livestock manure management based on IPCC default factors for emissions from the different types of livestock and management methods combined with FASOM results for livestock changes. We received comments that this was a good approach as it quantifies the indirect impacts of emissions associated with biofuel production. The same approach was used for the final rule analysis.

<u>Methane from Rice</u>: For the proposal, methane emissions from rice production were calculated by taking the FASOM output predicted changes in rice acres, resulting from the increase in biofuel production, and multiplying by default methane emission factors from IPCC

to generate GHG impacts. We received comments that this was a good approach as it quantifies the indirect impacts of emissions associated with biofuel production. The same approach was used for the final rule analysis.

ii. *International Agricultural Sector Impacts*

Agricultural Sector Inputs: For the proposal we determined international fertilizer and energy use emissions based on applying input data collected by the Food and Agriculture Organization (FAO) of the United Nations and the International Energy Agency (IEA) to the FAPRI-CARD crop output data and then applied GREET defaults for converting those inputs to GHG emissions.

As part of our public comment and peer review process we had this component of our analysis specifically peer reviewed. The main comment we received was to update our input data with newer data sources. Therefore, for the final rule analysis we updated fertilizer and pesticide consumption projections from the incorporation of updates made by the FAO to its Fertistat and FAOStat datasets, as well as the incorporation of more up-to-date fertilizer consumption statistics provided by a recent International Fertilizer Institute (IFA) report. This update had varying impacts on the amount of fertilizer used on different crops in different countries but in general increased the amount of fertilizer assumed and thus international agriculture lifecycle GHG emissions from fertilizer use for all biofuels.

Another comment from the peer review was that we should include lime use for some of the key crops modeled in our analysis. Lime use was not included in the proposal because of lack of international data on lime use by crop. Excluding lime used is an underestimate of international agriculture GHG emissions. For our final rule analysis we included lime use for sugarcane production in Brazil based on information received from Brazilian agricultural experts provided as part of the comment process. This led to an increase in GHG emissions from sugarcane farming. We did not include lime use for other crops in the final rule analysis because of lack of other data sources for other crops.

Others comments we received on our approach were that we were potentially underestimating GHG emissions from international agriculture energy use. Our proposal based international agriculture energy use on factors from the International Energy Agency (IEA) that included all energy use for agriculture that we divided by all agricultural sector land by country to get a GHG emission per acre for each country considered. The comment raised the issue that by using all agricultural land this includes pasture land that would not have the same energy input as crop production. Effectively, higher energy use from crop production was getting averaged with lower energy use for pasture and then this lower number was applied only to crop production. We specifically asked as part of our peer review for guidance and comment on our international agriculture energy use calculation. We did not receive significant comments or data to suggest that we change our approach and reviewers generally agreed we were using the best data available. Furthermore, the energy use values represent all agriculture including forestry and fishing which could in some countries be overestimating energy use for crop production. So for our final rule analysis we used the same approach as for the proposal to calculate international agriculture energy use GHG emissions.

We also received comments on the applicability of applying GREET defaults for fuel and fertilizer production to international fuel and fertilizer use to generate GHG emissions. The comments noted that GREET factors are developed for domestic US conditions and would not necessarily apply internationally. Specifically on the issue of nitrogen fertilizer production, the comments indicated that nitrogen fertilizer production internationally could rely on coal as a fuel source as opposed to natural gas used in the US, which would cause international GHG emissions associated with fertilizer production and hence biofuel production to be underestimated in our analysis. This was also an area we asked peer reviewers for comment and guidance. The peer review response generally supported our approach and did not offer suggestions for other data sources. So for our final rule analysis we used the same approach as for the proposal and applied GREET defaults to calculate international fertilizer production GHG emissions.

As was the case in the proposal and for domestic agriculture, we held the rates of international fertilizer application constant over time. This is true for both of our yield scenarios considered as well as for price induced yield increases. This was an area that was specifically addressed in our peer review of International Agricultural Greenhouse Gas Emissions and Factors. The reviewers supported the approach we have taken, for example indicating that generally crop production as a unit of fertilizer application has increased over time, therefore, crop yields have increased with the same or lower fertilizer applications.

N_2O Emissions: For the proposal we included N_2O emissions from fertilizer application by applying IPCC default factors for different crops in different countries. We use IPCC default factors because we do not have the same level of regional factors like we do in the US from the DAYCENT model. The IPCC guidance has emission factors for four sources of N_2O emissions from crops, Direct N_2O Emissions from Synthetic Fertilizer Application, Indirect N_2O Emissions from Synthetic Fertilizer Application, Direct Emissions from Crop Residues, and Indirect Emissions from Crop Residues. The proposal did not include N_2O emissions from the Direct and Indirect Emissions from Crop Residues for cotton, palm oil, rapeseed, sugar beet, sugarcane, or sunflower. These were not included for these crops because default crop-specific IPCC factors used in the calculation were not available.

Comments from our peer review process suggested that we include proxy emissions from these crops based on similar crop types that do have default factors. Therefore, for our final rule analysis we have included crop residue N_2O emissions from sugarcane production based on perennial grass as a proxy. Perennial grass is chosen as a proxy based on input from N_2O modeling experts. This change results in an increase in N_2O emissions from sugarcane and therefore sugarcane ethanol production compared to the proposal.

Livestock Emissions: Similar to domestic livestock impacts, enteric fermentation and manure management GHG emissions were included in our proposal analysis. The proposal calculated international livestock GHG impacts based on activity data provided by the FAPRI-CARD model (e.g., number and type of livestock by country) multiplied by IPCC default factors for GHG emissions.

Based on the peer review of the methodology used for the proposal it was determined that the calculations for manure management did not include emissions from soil application. These emissions were included for our final rule analysis but do not cause a significant change in the livestock GHG emission results.

Rice Emissions: To estimate rice emission impacts internationally, the proposal used the FAPRI-CARD model to predict changes in international rice production as a result of the increase in biofuels demand in the U.S. We then applied IPCC default factors by country to these predicted changes in rice acres to generate GHG emissions. We received comments that this was a good approach as it quantifies the indirect impacts of emissions associated with biofuel production. The same approach was used for the final rule analysis.

b. Land Use Change

The following sections discuss our final rulemaking assessment of GHG emissions associated with land use changes that occur domestically and internationally as a result of the increase in renewable fuels demand in the U.S. There are four main methodology questions addressed both domestically and internationally:

- Amount of Land Converted and Where
- Type of Land Converted
- GHG Emissions Associated with Conversion
- Timeframe of Emission Analysis

Each of those methodology components are discussed as are the comments we received as part of the comment and peer review process. We also outline in addition to our main FASOM and FAPRI-CARD approach a general equilibrium modeling approaches and its results.

i. *Amount of Land Area Converted and Where*

Based on a number of modeling changes made to the FASOM and FAPRI-CARD models since the NPRM, the amount of land use change resulting from an increase in biofuel demand in the U.S. is significantly lower in this FRM analysis for most renewable fuels. Many of the changes made were a direct result of comments received through the notice-and-comment period, comments received from the peer-reviewers, or as a result of incorporating new science that has become available since the analysis was conducted in the proposal. Some of the key changes that had the largest impact on the land use change estimates are included in this section. For additional information, see Chapter 2 of the RIA.

As discussed in the NPRM, one of the key factors in determining the amount of new land needed to meet an increase in biofuel demand is the treatment of co-products of ethanol and biodiesel production. We received many comments on this topic, particularly on the amount of corn and soybean meal a pound of DGS, the byproduct of dry mill grain ethanol production, can replace in animal feed. For the final rule, we predict that distiller grains will be absorbed by livestock more efficiently over time. We updated the displacement rate assumptions in the FASOM and FAPRI-CARD models based on comments we received and on the recent research conducted by Argonne National Laboratory and others.[167] According to this research, one pound of DGS replaces more than a pound of corn and/or soybean meal in beef and dairy rations, in part because cattle fed DGS show faster weight gain and increased milk production compared to those fed a traditional diet. While this study represents a significant increase over current DGS replacement rates, we believe it is reasonable to assume that improvements will be made in the use and efficiency of DGS over time as the DGS market matures, the quality and consistency of DGS improves, and as livestock producers learn to optimize DGS feed rations. As a result of this modification, less land is needed to replace the amount of corn diverted to ethanol production. Additional details on the DGS assumptions are included in Chapters 2 and 5 of the RIA.

A second factor that can have a significant impact on the amount of land that may be converted as a result of increasing biofuel demand are changes in crop yields over time. As discussed in the NPRM, our proposal based domestic yields on USDA projections for both the reference case and the control case. As discussed in Section V.B.1.c, for this FRM we have also included scenarios that use higher yield projections in both the reference case and the control case. However, in the NPRM we also requested comment on whether the higher prices caused by an increased in demand for biofuels would increase future yield projections in the policy case beyond the yield trends in the reference case (sometimes referred to as "price induced yields"), or whether these price induced yields would be offset by the reduction in yields associated with expanding production onto new marginal acres (sometimes referred to as extensification). Based on the comments we received, along with additional historical trend analysis conducted by FAPRI-CARD, the international agricultural modeling framework now incorporates a price induced yield component.[168] The new yield adjustments are partially offset by the extensification factor, however, the combined impact is that fewer new acres are needed for agricultural production to meet world agricultural demands.

One additional change we made to the yield assumptions was to update the FASOM model with new analysis by Pacific Northwest National Laboratories (PNNL) on switchgrass yields.[169] We included this new data for two reasons. First, we received several comments that our assumptions on switchgrass yields were too low, based on more recent field work. In addition, for out NPRM analysis, we did not have data for switchgrass yields in certain regions of the US. Therefore, the PNNL data helped to fill a pre-existing data gap. As a result of these updates, less land is needed per gallon of switchgrass ethanol produced. Additional details on switchgrass yields and other agricultural sector modeling assumptions are included in RIA Chapter 5.

One of the major changes made to the FAPRI-CARD model between the NPRM and FRM includes the more detailed representation of Brazil through a new integrated module. The Brazil module was developed by Iowa State with input from Brazilian agricultural sector experts

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[167] Salil, A., M. Wu, and M. Wang. 2008. "Update of Distillers Grains Replacement Ratios for Corn Ethanol Life-Cycle Analysis." Available at http://www.transportation.anl.gov/pdfs/AF/527.pdf.

[168] *Technical Report: An Analysis of EPA Renewable Fuel Scenarios with the FAPRI-CARD International Models*, CARD Staff, January, 2010

[169] Thomson, A.M., R.C. Izarrualde, T.O. West, D.J. Parrish, D.D. Tyler, and J.R. Williams. 2009. Simulating Potential Switchgrass Production in the United States. PNNL-19072. College Park, MD: Pacific Northwest National Laboratory.

and we believe it is an improvement over the approach used in the proposal. In the NPRM, we requested additional data for countries outside the U.S. We received comments encouraging us to use regional and country specific data where it was available. We also received comments encouraging us to take into account the available supply of abandoned pastureland in Brazil as a potential source of new crop land. The new Brazil module addresses these comments. Since the Brazil module contains data specific to six regions, this additional level of details allows FAPRI-CARD to more accurately capture real-world responses to higher agricultural prices. For example, double cropping (the practice of planting a winter crop of corn or wheat on existing crop acres) is a common practice in Brazil. Increased double cropping is feasible in response to higher agricultural prices, which increases total production without increasing land use conversion. The new Brazil module also explicitly accounts for changes in pasture acres, therefore accounting for the competition between crop and pasture acres. Furthermore, the Brazil module explicitly models livestock intensification, the practice of increasing the number of heads of cattle per acre of land in response to higher commodity prices or increased demand for land.

In addition to modifying how pasture acres are treated in Brazil, we also improved the methodology for calculating pasture acreage changes in other countries. We received several comments through the public comment period and peer reviewers supporting a better analysis of the interaction between crops, pasture, and livestock. In the NPRM, although we accounted for GHG emissions from livestock production (e.g., manure management), we did not explicitly account for GHG emissions from changes in pasture demand. In response to comments received, our new methodology accounts for changes in pasture area resulting from livestock fluctuations and therefore captures the link between livestock and land used for grazing. Based on regional pasture stocking rates (livestock per acre), we now calculate the amount of land used for livestock grazing. The regional stocking rates were determined with data on livestock populations from the UN Food and Agricultural Organization (FAO) and data on pasture area measured with agricultural inventory and satellite-derived land cover data. As a result of this change, in countries where livestock numbers decrease, less land is needed for pasture. Therefore, unneeded pasture acres are available for crop land or allowed to revert to their natural state. In countries where livestock numbers increase, more land is needed for pasture, which can be added on abandoned cropland or unused grassland, or it can result in deforestation. We believe this new methodology provides a more realistic assessment of land use changes, especially in regions where livestock populations are changing significantly. For additional information on the pasture replacement methodology, see RIA Chapter 2.

Although the total amount of land use conversion is lower in the FRM analysis compared to the NPRM analysis, the regional distribution of this land use change has shifted. Due to the many changes made in response to comments associated with agriculture and livestock markets, Brazil is now much more responsive to changes in world biofuel and agricultural product demand. As a result, a larger portion of the projected land use change occurs in Brazil compared to the NPRM analysis. Additional details on the geographical location of land use change are included in Chapter 2 of the RIA.

ii. *Type of Land Converted*

Based on a number of improvements in our analysis, the types of land affected by biofuel-induced tend to be less carbon intensive compared to the NPRM. Therefore, the net effect of our revisions to this part of our analysis significantly reduced land use change GHG emissions. The updated FAPRI-CARD Brazil model, discussed in the previous section, showed more pasture expansion in the Amazon which increased land use change emissions. However, the most important revisions to this part of our international analysis, in terms of their net effect on GHG emissions, were improvements that we made in our modeling of the interactions between livestock, pasture, crops and unused, or underutilized, grasslands globally. In the NPRM we made the broad assumption that international crop expansion would necessarily displace pasture, which would require an equivalent amount of pasture to expand into forests and shrublands. In the FRM analysis as discussed in the previous section, we have linked international changes in livestock production with changes in pasture area to allow for pasture abandonment in regions where livestock production decreases as a result of biofuel production. We also incorporated the ability of pasture to expand onto unused, or underutilized, grasslands and savannas which on a global basis reduced the amount of forest conversion compared to the proposal. These revisions, as well as a quantitative uncertainty assessment, are discussed in this section.

In the same way that the amount and location of land use change is important, the type of land converted is also a critical determinant of the magnitude of the GHG emissions impacts associated with biofuel production. For example, the conversion of rainforest to agriculture results in a much larger GHG release than conversion of grassland. In the proposed rule analysis we used two approaches, based on the best available information to us at the time, to evaluate the types of land that would be affected domestically and internationally. Domestically, we used the FASOM model, which simulates rental rates for different types of land (e.g., forest, pasture, crop) and chooses the land uses that would produce the highest net returns. Internationally, we used the FAPRI-CARD/Winrock analysis whereby historical land conversion trends, as evaluated with satellite imagery, are used to determine what types of land are affected by agricultural land use changes in each country or sub-region.

In the proposed rule we also explained several other options to determine what types of land will be affected by biofuel-induced land use changes, such as the use of general equilibrium models. EPA specifically sought expert peer review input and public comment on our approach and all of the analytical options for this part of the lifecycle assessment. The expert peer reviewers agreed that EPA's approach was scientifically justifiable, but they highlighted problematic areas and suggested important revisions to improve our analysis. The public comments received on this issue expressed a wide range of views regarding EPA's approach. In general, the commenters that objected to our analytical approach raised similar concerns as the peer reviewers, such as the need for more data validation and uncertainty assessment. As discussed below, we made significant improvements to our analysis based on the recommendations and comments we received. Based on the peer reviewers agreement that our general approach is scientifically justifiable, and in light of the significant improvements made, we think that our approach represents the best available analysis of the types of land affected by biofuel-induced land use changes. We did consider a range of other analytical options, but based on all of the information considered and the requirements for this analysis, we did not find any alternative approaches that are superior at this time. As part of periodic updates to the lifecycle analysis, we will continue to consider ways to improve this part of our analysis, as well as the merits of alternate approaches.

Domestic: In response to comments received, we made two major improvements to the FASOM model for the final rulemaking. As discussed in the NPRM and supported by comments, we were able to include the forestry sector into the FASOM analysis. Only the agricultural sector of FASOM was analyzed for the NPRM, due to the fact that the forestry sector component was undergoing model modifications. For this FRM analysis, we were able to use the fully integrated forestry and agricultural sector model, thereby capturing the interaction between agricultural land and forests in the U.S. In addition, the inclusion of the forestry model allows us to explicitly model the land use change impacts of the competing demand for cellulosic ethanol from agricultural sources with cellulosic ethanol from logging and mill residues. As a result of this modification, the FRM analysis includes some land use conversion from forests into agriculture in the U.S. as a result of the increased demand for renewable fuels.

The second major modification we made in response to comments was the disaggregation of different types of land included in FASOM. In the proposed rulemaking, the FASOM model included three major categories of land: cropland, pasture, and acres enrolled in the Conservation Reserve Program (CRP). Although this categorization allowed for a detailed regional analysis of land used to grow crops, acres used for livestock production were not fully captured. We received comments requesting a more detailed breakdown of land types in order to capture the interaction between livestock, pasture, and cropland. Therefore, the FASOM model now includes rangeland, pasture and forest land that can be used for grazing. Since we also received comments that we should take into account the potential for idle land to be used for other purposes such as the production of cellulosic ethanol, FASOM now accounts for the amount of land within each category that is either idle or used for production.

These two major modifications to the FASOM model now allow us to explicitly track land transfers between various land categories in the U.S. As a result, we can more accurately capture the GHG impacts of different types of land use changes domestically. More detail and results of the FASOM model can be found in Section V.B.1.b of the preamble.

Intern ational: The proposed rule included a detailed description of the FAPRI-CARD/Winrock approach used to determine the type of land affected internationally. This approach uses satellite data depicting recent land conversion trends in conjunction with economic projections from the FAPRI-CARD model (an economic model of global agricultural markets) to determine the type of land converted internationally. In the proposed rule we described areas of uncertainty in this approach, illustrated the uncertainty with sensitivity analyses, and discussed other potential approaches for this analysis. To encourage expert and stakeholder feedback, EPA specifically invited comment on this issue, held public hearings and workshops, and sponsored an independent peer-review, all of which specifically highlighted this part of our analysis for feedback. While there were a wide range of views expressed in these forums, the feedback received by the Agency generally supported the FAPRI-CARD/Winrock approach as appropriate for this analysis. For example, all five experts that peer reviewed EPA's use of satellite imagery agreed that it is scientifically justifiable to use historic remote sensing data in conjunction with agricultural sector models to evaluate and project land use change emissions associated with biofuel production. Additionally, the peer reviewers and public commenters highlighted problematic areas and suggested revisions to improve our analysis. Below, we describe the key revisions that were implemented which have significantly improved our analysis based on the feedback received.

FAPRI-CARD/Satellite Data Approach: As described above in Section V.B.1.b, the FAPRI-CARD model was used to determine the amount of land use change in each country/region in response to increased biofuel production. Because the FAPRI-CARD model does not provide information about what type of land is converted to crop production or pasture, we worked with Winrock International to evaluate the types of land that would be affected internationally. Winrock is a global nonprofit organization with years of experience in the development and application of the IPCC agricultural forestry and other land use (AFOLU) guidance. For the proposed rule, we used satellite data from 2001-2004 to provide a breakdown of the types of land converted to crop production. A key strength of this approach is that satellite information is based on empirical observations which can be verified and statistically tested for accuracy. Furthermore, it is reasonable to assume that recent land use change decisions have been driven largely by economics, and, as such, recent patterns will continue in the future, absent major economic or land use regime shifts caused, for example, by changes in government policies.

As discussed above, all five of the expert peer reviewers that reviewed our use of satellite imagery for this analysis agreed that our general approach was scientifically justifiable. However, all of the peer reviewers qualified that statement by describing relevant uncertainties and highlighting revisions that would improve our analysis. Some of the public commenters supported EPA's use of satellite imagery, while other expressed concern. In general, both sets of public commenters—those in favor and opposed—outlined the same criticisms and suggestions as the expert peer reviewers. Among the many valuable suggestions for satellite data analysis provided in the expert peer reviews and public comments, several major recommendations emerged: EPA should use the most recent satellite data set that covers a period of at least 5 years; EPA should use higher resolution satellite imagery; EPA's analysis should consider a wider range of land categories; EPA should improve it's analysis of the interaction between cropland, pasture and unused or underutilized land; and EPA's analysis should include thorough data validation and a full assessment of uncertainty. Below, we describe these and other recommendations and how we addressed each of them to improve our analysis. Based on the peer reviewers agreement that our general approach is scientifically justifiable, and in light of the significant improvements made, we think that our approach represents the best available analysis of the types of land affected internationally.

One of the fundamental improvements in this analysis since the proposed rule is that it now provides global coverage. The analysis for the proposed rule included satellite imagery for 6 land categories in 314 regions across 35 of the most important countries, with a weighted average applied to the rest of the world. We have since completed a global satellite data analysis including 9 land categories in over 750 distinct regions across 160 countries. This was an analytical improvement that we committed to do in the proposed rule. As described below, the other major analytical enhancements were conducted in response to the many technical recommendations that we received as part of the peer review and public comment process.

All of the expert peer reviewers agreed that the version 4 MODIS data set used in the proposed rule, which covers 2001-2004 with one square-kilometer (1km) spatial resolution, was appropriate for our analysis given the goals of the study at the time. However, almost all of the reviewers strongly recommended using a data set covering a longer time period. The reviewers argued that the 3-year time period from 2001-2004 was too short to capture the often gradual, or sequential, cropland expansion that has been observed in the tropics. The short time period may also show unusual or temporary trends in land use caused by short-term policy changes or market influences. The reviewers suggested that remote sensing observations covering 5-10 years would be adequate to address these problems. The reviewers also recommended that remote sensing observations should be as recent as possible in order to capture current land use change drivers and patterns (e.g., political systems, infrastructure, and protected areas). To use the best available data and respond to the peer reviewers' recommendations, the analysis was updated to include the most recent MODIS data set, version 5, which covers the time period 2001-2007. MODIS land cover products are not available for years prior to 2001, so it is not currently possible to analyze a time period longer than six years (i.e., 2001-2007) with a single, or consistent, data set. Thus, consistent with the peer review recommendations, we are now using the most recent global data set which covers at least 5 years. There are other advantages to using the version 5 MODIS data, such as improved spatial resolution, and robust data validation, which are discussed below.

There was strong agreement among the peer reviewers that higher resolution satellite imagery would be an important improvement over the 1-km resolution data used in the proposed rule analysis. Higher spatial resolution is especially useful in categorizing highly fragmented landscapes. One of the reviewers hypothesized that land use change driven by biofuel production would likely involve large parcels of land, and thus 1-km resolution may be sufficient. However, all of the reviewers agreed that higher resolution data would be preferable. A number of the peer reviewers specifically said that the version 5 MODIS data set, with 500 meter resolution, would be adequate. With four-times higher spatial resolution than version 4, the peer reviewers anticipated that the 500m imagery would classify less area of "mixed class" land, thus providing a more detailed representation of the land in that category. Consistent with the peer reviewer's recommendations and with our goal to use the best available information, our analysis was updated with the higher resolution version 5 MODIS data.

Related to the issue of spatial resolution, the peer review experts were asked whether they would recommend augmenting our global analysis with even higher resolution data for specific regions where there is a high degree of agricultural land use change. All of the peer reviews agreed that this type of analysis would be worthwhile. In response to this recommendation, we analyzed select geographic regions (e.g., Brazil, India) with the higher resolution 30m Landsat data set covering 2000-2005. The Landsat data set does not currently provide global coverage, thus it was not an option for use in the full analysis; instead, it was used as a way to check/validate the appropriateness of the version 5 MODIS imagery. In general, the higher resolution data showed similar land use change patterns as the MODIS data. The results of this analysis are discussed further in Chapter 2 of the RIA.

Another issue that we invited comments on was the re-classification of the MODIS data from 17 land cover categories into 6 aggregated categories (e.g., open and closed shrubland were both re-classified as shrubland). The category aggregation was intended to remove unnecessary complexity from the analysis. All five expert reviewers agreed that the methodology used to re-classify land cover categories using International Geosphere-Biosphere Programme (IGBP) land definitions was sound; however, the reviewers recommended inclusion of more than 6 aggregated land categories. The reviewers specifically recommended the addition cropland/natural vegetation mosaic, permanent wetlands, and barren or sparsely vegetated land, all of which are now included in our analysis. Consistent with these recommendations, there are 9 aggregate land categories in our revised analysis: barren, cropland, excluded (e.g., urban, ice, water bodies), forest, grassland, mixed (i.e., cropland/natural vegetation mosaic), savanna, shrubland and wetland. These land cover categories capture all significant types of land affected by agricultural land use changes. As described below in Section V.B.2.b.iii, we also estimated carbon sequestrations for all of these land categories. The impact of adding these land categories to our analysis is discussed further in RIA Chapter 2.

Another important addition to our analysis was consideration of the types of land affected by changes in pasture area, and the interaction of pasture land with cropland. In the proposed rule, we made a broad assumption that the total land area used for pasture would stay the same in each country or region. Thus, in the proposed rule, we assumed that any crop expansion onto pasture would necessarily require an equal amount of pasture to be replaced on forest or shrubland. We received a large number of comments questioning these assumptions, and the expert peer reviewers encouraged us to develop a better representation of the interactions between cropland and pasture land. As described above in Section V.B.2.6.i, the results from the FAPRI-CARD model are now used to determine pasture area changes in each country or region. In regions where we project that pasture and crop area both increase, the land types affected by pasture expansion are determined using the same analysis used for crop expansion. This new approach accounts for the ability of pasture to expand on to previously unused, or underutilized, grasslands and savanna. In regions where we project that crop and pasture area will change in opposite directions (e.g., crop area increases and pasture decreases) we assume that crops will expand onto abandoned pasture, and vice versa. Our analysis also now accounts for carbon sequestration resulting from crop or pasture abandonment. We used our satellite analysis, which shows the dominant ecosystems and land cover types in each region, to determine which types of ecosystems would grow back on abandoned agricultural lands in each region. More information about our analysis of pasture and abandoned agricultural land are provided in RIA Chapter 2.

A sub-set of the expert peer reviewers recommended combining the historic satellite imagery with other information on land use change drivers (e.g., transportation infrastructure, poverty rates, opportunity costs) as an additional means to estimate the types of land affected. Consideration of these types of information could potentially address two conceptual issues with the use of satellite imagery in this analysis: first, biofuel-induced land use change could affect different types of land than the generic agricultural expansion captured by the historic data; and second, future land use change patterns may differ from historic patterns. Our concerns with the first issue are allayed to some degree by one of the peer reviewers who observed, "While it is theoretically possible that the changes in land use resulting from biofuel production occur in ecosystems or regions that would not be the ones affected by other drivers, this doesn't appear very likely."[170] Furthermore, the economic drivers of land use change are to a large degree captured by the economic models that are used in our analysis. For example, the FAPRI-CARD model considers economic drivers in its projections of where and how much crop production will change as a result of specifically biofuel-induced changes. The second issue is also addressed to some degree by the FAPRI-CARD model which includes baseline forecasts of future international agricultural, economic and demographic conditions. Furthermore, as discussed above, we used the most recently available satellite data sets in order to capture the most current land use change drivers. Thus, while we think that these issues are currently addressed to a scientifically justifiable degree for the purposes of this analysis, we recognize that these are areas for future investigation, and we have tried to capture the uncertainty from these factors in uncertainty and sensitivity analyses as described below.

While EPA has made significant improvements to the methodology in response to peer review comments, the use of satellite data for forecasting land use changes is a key area of uncertainty in the analysis. To facilitate substantive comments on the impact of uncertainty in international land use changes, and how to address the uncertainty, the proposed rule highlighted areas of uncertainty and included multiple sensitivity analyses. For example, we presented a range of lifecycle results assuming at the high-end that all land conversion caused deforestation and at the low-end that biofuels would cause no deforestation. Further, EPA sought input on this issue in public hearings and workshops, and expert feedback through the independent peer review. The feedback we received, both from experts and the public, overwhelmingly supported a more systematic analysis of the uncertainty in using satellite data to project biofuel-induced land use change patterns. Additionally, commenters recommended more data validation, especially regarding the satellite imagery. To respond to these comments, we incorporated satellite imagery validation and conducted a Monte Carlo analysis of the MODIS satellite data using assessments provided by NASA to quantitatively evaluate the uncertainty in our application of satellite imagery.

One benefit of using the MODIS data set is that it is routinely and extensively validated by NASA's MODIS land validation team. NASA uses several validation techniques for quality assurance and to develop uncertainty information for its products. NASA's primary validation technique includes comparing the satellite classifications to data collected through field and aircraft surveys, and other satellite data sensors. The accuracy of the version 5 MODIS land cover product was assessed over a significant set of international locations, including roughly 1,900 sample site clusters covering close to 150 million square kilometers. The results of these validation efforts are summarized in a "confusion matrix" which compares the satellite's land classifications with the actual land types observed on the ground. We used this information to assess the accuracy and systematic biases in the published MODIS data. In general, the validation process found that MODIS version 5 was quite accurate at distinguishing forest from cropland or grassland. However, the satellite was more likely; for example, to confuse savanna and shrubland because these land types can look quite similar from space.

Using the data validation information from NASA about which types of land MODIS tends to confuse which each other, our Monte Carlo analysis was able to account for systematic

[170] Peer Review Report, Emissions from Land Use Change due to Increased Biofuel Production: Satellite Imagery and Emissions Factor Analysis, July 31, 2009, p. 2

misclassifications in the MODIS data set. Therefore, part of the Monte Carlo analysis can be viewed as a way to correct and reduce the inaccuracies in the MODIS data. After this correction is performed, the uncertainty in the satellite data is no longer solely a function of the accuracy of the satellite. Instead, the sizes of the standard errors for each classification are also a function of the sample sizes in the data validation exercise. For example, if NASA validated every pixel on Earth, the corrected data set would be 100% accurate, even if the original satellite data were only 50% accurate. Similarly, although NASA reports that the overall accuracy of the MODIS version 5 land cover data set is approximately 75%, the standard errors after the Monte Carlo procedure are less than 5% for each aggregate land category. These standard errors were used to quantify the uncertainty added by the satellite data used in our analysis. This procedure and the results are described in more detail in Chapter 2 of the RIA.

It should be noted that our assessment of satellite data uncertainty did not try to fully quantify the uncertainty of using historical data to make future projections about the types of land that would be affected internationally. As noted above, we think it is reasonable to assume that in general, recent land use change patterns will continue in the future absent major economic or land use regime shifts caused, for example, by changes in government policies. Thus, our uncertainty assessment provides a reasonable estimate of the variability in land use change patterns absent any fundamental shifts in the factors that affect land use patterns. However, our uncertainty assessment does not attempt to fully quantify the probability of major shifts in land use regimes, such as the implementation of effective international policies to curb deforestation.

Some of the peer reviewers recommended a satellite imagery analysis approach known as change detection, instead of the “differencing” approach used in the Winrock analysis. However, there was disagreement among the peer reviewers on this point, with one peer reviewer saying that thematic differencing between land cover maps generated for two specific dates, as conducted in this study, provides the best approach for detecting and analyzing land use pattern changes globally. In general terms, the differencing method employed by Winrock compared global land cover maps from 2001 and 2007 to evaluate the pattern of land use change during this period. Thus, the differencing method shows all of the land that changed categories, as well as all of the land that stayed the same over this period. For change detection, instead of using comprehensive land cover maps, the data set only shows land categories that changed. One advantage of change detection is that it is better suited to capture the sequential nature of land use changes, e.g., a forest could be converted to savanna, then grassland and then cropland. The differencing method that we employed lends itself more readily to comprehensive global analysis, data validation, and uncertainty assessment. Given the timeframe and priorities for our analysis, we think that the differencing method provides the best approach available at this time. However, we will continue to consider alternative analytical techniques, such as change detection, for use as part of periodic updates to this analysis.

Some of the peer reviewers recommended additional alternative technical approaches for satellite data and land use change analysis. For example, some of the reviewers recommended the use of satellite imagery to identify specific crop-types and rotations, and one reviewer suggested that EPA develop a new interactive spatial model. The Summary and Analysis of Comments document includes discussion of these and other technical comments and recommendations that are not covered here.

iii. *GHG Emissions Associated with Conversion*

(1) *Domestic Emissions*

GHG emissions impacts due to domestic land use change are based on GHG emissions the FASOM model generates in association with land type conversions projected in the model. In the proposed rule analysis, estimates of land use change emissions were limited to conversion between different types of agricultural land (e.g., cropland, fallow cropland, pasture). The analysis did not allow for the addition of new domestic agricultural land.

In response to feedback EPA received during the public comment period and based on commitments EPA made in the NPRM, several changes and additions have augmented the analysis of domestic land use change GHG emissions since the proposed rule analysis. The addition of the forest land types and the interaction between cropland, pastureland, forestland, and developed land to the FASOM model provides a more complete emissions profile due to domestic land use change (see Section V.B.4.b.ii). We have updated soil carbon accounting based on new available data. Lastly, the methodology now captures GHG emission streams over time associated with discrete land use changes.

For agricultural soils, FASOM models GHG emissions associated with changes in crop production acreage and with changes in crop type produced. FASOM generates soil carbon factors for cropland and pasture according to IPCC Agriculture, Forestry, and Other Land Use (AFOLU) Guidelines. In the proposed rule, we committed to updating FASOM soil carbon accounting for agriculture. Per our commitment, we have updated FASOM soil carbon accounting for cropland and pasture using the latest DAYCENT modeling from Colorado State University.

In the proposed rule, EPA committed to incorporate the forestry sector and the GHG emission impacts due to the land use interactions between the domestic agricultural and forestry sectors into the FASOM analysis. We received comment supporting the incorporation of the forestry sector. By including the forestry sector in the FASOM domestic model (see Section V.B.4.b.ii), we have incorporated GHG emission impacts associated with change in forest above-ground and below-ground biomass, forest soil carbon stocks, forest management practices (e.g. timber harvest cycles), and forest products and product emission streams over time. Forest carbon accounting in FASOM is based on the FORCARB developed by the U.S. Forest Service and on data derived largely from the U.S. Forest Service RPA modeling system.

With the changes to FASOM discussed above, we also updated the final calculation method of domestic land use change GHG emissions to account for FASOM's cumulative assessment of GHG emissions and the continuous (rather than discrete) nature of soil carbon and forest product emissions. For each category of agricultural and forestry land use emissions, we calculated the mean cumulative emissions from the initial year of FASOM modeling (2000) to 2022. Changes in agricultural and forest soil carbon and forest products have a stream of GHG emissions associated with them in addition to the initial pulse associate with a discrete instance or year of land use change. For each of these categories FASOM calculates the emissions over time associated with the mean land use change over a year. We included in total domestic land use change emissions the annualized emission streams associated with all agricultural soil, forest soil, and forest product changes included in the mean cumulative emissions (2000-2022) for 30 years after 2022.

(2) *International Emissions*

Based on input from the expert peer review and public comments, we incorporated new data sources and made other methodological improvements in our estimates of GHG emissions from international land conversions. Some of these modifications increased land use change GHG emissions compared to the NPRM, such as the consideration of carbon releases from drained peat soils. Other modifications, such as more conservative foregone sequestration estimates, tended to decrease land use change GHG emissions. For example, our estimates of emissions per acre of deforestation in Brazil tended to increase because of improved data on forest biomass carbon stocks in that region. However, for example, our deforestation estimates in China decreased, in part because of new data on foregone forest sequestration. The net effect of the revisions varied depending on the location and types of land use changes in each biofuel scenario. The major changes to this part of our analysis, including a quantitative uncertainty assessment, are discussed in this section.

To determine the GHG emissions impacts of international land use changes, we followed the 2006 IPCC Agriculture, Forestry, and Other Land Use (AFOLU) Guidelines.[171] We worked with Winrock, which has years of experience developing and implementing the IPCC guidelines, to estimate land conversion emissions factors, including changes in biomass carbon stocks, soil carbon stocks, non- CO_2 emissions from clearing with fire and foregone forest sequestration (i.e., lost future growth in vegetation and soil carbon). In addition to seeking comment on our analysis in the proposed rule, EPA organized public hearings and workshops, and an expert peer review specifically eliciting feedback on this part of the lifecycle analysis. All of the expert peer reviewers generally felt that our analysis followed IPCC guidelines and was scientifically justifiable; however, they did make several suggestions of new data sources and recommended areas that could benefit from additional clarification. Based on the detailed comments we received, we worked with Winrock to make a number of important revisions, which have significantly improved this part of our analysis.

The proposed rule analysis included land conversion emissions factors for 5 land categories in 314 regions across 35 of the most important countries, with a weighted average applied to the rest of the world. We augmented this analysis to provide global coverage, including emissions factors for 10 land categories in over 750 regions across 160 countries. Other significant improvements included incorporation of new data sources, emissions factors for peat soil drainage, sequestration factors for abandoned agricultural land, and a full uncertainty assessment considering every data input.

Another significant improvement in our analysis was incorporation of higher resolution soil carbon data. One of the expert peer reviewers commented that the weakest part of EPA's

[171] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Agriculture, Forestry and Other Land Use (AFOLU). See http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

international emissions factor analysis for the proposed rule was the global soil carbon map that was used because of its coarse resolution. To address this comment, we incorporated the new Harmonized World Soil Database, released in March 2009. This dataset provides one square kilometer spatial resolution, which is a major improvement compared to the proposed rule analysis. This dataset also includes an updated soil map of China that the peer reviewers recommended. Using this updated soil carbon data, the change in soil carbon following conversion of natural land to annual crop production was estimated following the 2006 IPCC guidelines. When land is plowed in preparation for crop production the soil loses carbon over time until a new equilibrium is established. To calculate soil carbon emissions the IPCC approach considers both tillage practices and agricultural inputs. Some of the peer reviewers expressed concern with our annual soil carbon change estimates, which assumed a constant rate of change over 20 years. However, for analytical timeframes greater than 20 years, such as used in our lifecycle analysis, the peer reviewers agreed that the our approach was scientifically justifiable. More information about soil carbon stock estimates is available in Chapter 2 of the RIA.

The expert peer reviewers generally agreed that EPA's estimate of forest carbon stocks followed IPCC guidelines and used the best available data. They did, however, recommend that the analysis could be updated with improved forest biomass maps as they become available. Consistent with these suggestions, we incorporated improved forest biomass maps for regions where they were available. More information about the specific data sources used is available in RIA Chapter 2.

In addition to estimating forest carbon stocks for each region, EPA's analysis also includes estimates of annual forest carbon uptake. When a forest is cleared the future carbon uptake from the forest is lost; this is known as foregone forest sequestration. In the proposed rule, to estimate annual forgone forest sequestration, we used IPCC default data for the growth rates of forests greater than 20 years old. The expert peer reviewers noted that these estimates could be refined with more detailed information from the scientific literature. Many of the public commenters were also concerned that EPA's approach overestimated foregone sequestration because it did not adequately account for natural disturbances, such as fires and disease. To address these comments, our analysis has been updated with peer reviewed studies of long-term growth rates for both tropical and temperate forests. These estimates are based on long-term records (i.e., monitoring stations in old-growth forests for the tropics and multi-decadal inventory comparisons for the temperate regions) and reflect all losses/gains over time. These studies show that the old-growth forests in the tropics that many once assumed to be in "steady state" (i.e., carbon gains equal losses) are in fact still gaining carbon. In summary, our analysis now includes more conservative foregone forest sequestration estimates that account for natural gains and losses over time. More information about these estimates is provided in RIA Chapter 2.

Another consideration when estimating GHG emissions resulting from deforestation is that some of the wood from the cleared forest can be harvested and used in wooden products, such as a table, that retain biogenic carbon for a long period of time. Some commenters argued that consideration of the use of harvested wood in products would decrease land use change emissions and reduce the impacts of biofuel production. As part of analysis for the proposed rule, we investigated the share of cleared forest biomass that is typically used in harvested wood products (HWP). However, we did not account for this factor in the proposed rule after it was determined that HWP would have a very small impact on the magnitude of land use change emissions. A number of commenters expressed concern that we did not account for HWP, and they argued that HWP would be more significant than we had determined. However, in response to specific questions on this topic, all of the expert peer reviewers agreed that EPA had properly accounted for HWP and other factors (e.g., land filling) that could prevent or delay emissions from land clearing. One of the peer reviewers noted that forests converted to croplands are generally driven by interests unrelated to timber, and thus the trees are simply burned and exceptions are probably of minor importance. To study this issue further, we looked at FAO timber volume estimates for 111 developing countries, and published literature on the share of harvested timber used in wood products and the oxidation period for wood products, such as wood-based panels and other industrial roundwood. Consistent with the peer reviewers' statements, our analysis concluded that even in countries with high rates of harvested timber utilization, such as Indonesia, a very small share of harvested forest biomass would be sequestered in HWP for longer than 30 years. The details of our HWP analysis are discussed further in RIA Chapter 2. This is an area for further work, but based on our analysis, and the feedback from expert commenters, we do not expect that consideration of HWP would have a significant impact on the magnitude of GHG emissions from international deforestation in our analysis. Furthermore, the range of outcomes from consideration of HWP is indirectly captured in our assessment of forest carbon stock uncertainty, which is described below.

The land conversion emissions estimates used in our analysis consider the carbon stored in crop biomass. In the proposed rule, we used the IPCC default biomass sequestration factor of 5 metric tons of carbon per hectare for annual crops, and applied this value to all crops globally. The final rule analysis now distinguishes between annual and perennial crops, with separate sequestration estimates for sugarcane and oil palm determined from the scientific literature. The peer reviewers suggested approaches to refine our biomass carbon estimates for different types of annual crops, e.g., for corn versus soybeans. However, we determined that adding crop-specific biomass sequestration estimates would have a very small impact on our results, because in general annual cropland carbon stocks range only from 3 to 7 tons per hectare and the average would likely be very close to the IPCC default factor currently applied. This is an area for future work, but we are confident that it would have very small impact. Furthermore, the range of potential outcomes is captured in the uncertainty analysis described below.

Other issues that were covered in the expert peer review and public comments included EPA's carbon stock estimates for grasslands, savanna, shrublands and wetlands, and our assumptions about which regions use fire to clear land prior to agricultural expansion. There is less data available for these parameters relative to some of the other issues discussed above, e.g., forest carbon stocks. Therefore, we worked to use expert judgment to derive global estimates for these parameters. In general, the peer reviewers thought that EPA's approach to these issues was reasonable and scientifically justifiable. Some of the peer reviewers recommended more resource-intensive techniques to refine some of our estimates. For example, regarding the issue of clearing with fire, one of the peer reviewers suggested that we could review fire events in the historical satellite data to estimate where fire is most commonly used. We carefully considered these suggestions, but did not make significant revisions to our analysis of these issues. Our review concluded that given the timeframe and goals of our analysis, the approach used in the proposed rule was most appropriate. We recognize that these are areas for future work, and we will consider new data as part of periodic updates. Furthermore, our uncertainty analysis, described below, considered the fact that these are areas where less data is available.

Other improvements in our analysis included the addition of emissions from peat soil drainage in Indonesia and Malaysia, and sequestration factors for abandoned agricultural land. Consistent with the expert peer reviewers' recommendations, we considered a number of recent studies to estimate average carbon emissions when peat soils are drained in Indonesia and Malaysia (the countries where peat soil is sometimes drained in preparation for new agricultural production). To estimate annual sequestration on abandoned agricultural land we used our foregone sequestration estimates and other data from IPCC. More information about these estimates is available in RIA Chapter 2.

As discussed in Section V.A.2, the uncertainty of land use change emissions is an important consideration in EPA's threshold determinations as part of this rulemaking. We conducted a full assessment of the uncertainty in international land use change emissions factors consistent with 2006 IPCC guidance.[172] This analysis considers the uncertainty in the every parameter used in our emissions factor estimates. Standard deviations for each parameter were estimated based on the quality and quantity the underlying data. For example, in our analysis the standard errors (as a percent of the mean) tend to be smallest for forest carbon stocks in Brazil, because a large amount of high quality/resolution data was considered to estimate that parameter. Standard errors are largest for parameters that were estimated by scaling other data, or applying IPCC defaults, e.g., savanna carbon stocks in Yemen. More detail about our estimate of parameter uncertainty is available in RIA Chapter 2.

Following IPCC guidance, the uncertainties in the individual parameters of an emission factor can be combined using either error propagation methods (IPCC Tier 1) or Monte Carlo simulation (IPCC Tier 2). We used the Tier 2 Monte Carlo simulation method for this analysis. Monte Carlo is a method for analyzing uncertainty propagation by randomly sampling from the probability distributions of model parameters, calculating the results of the model from each sample, and characterizing the probability of the outcomes. An important consideration for Monte Carlo analysis is the treatment of correlation, or dependencies, among parameter errors. Strong positive correlation among parameter errors will result in greater overall uncertainty. As a simplified example, if the errors in our forest carbon stock estimates are positively correlated, then if we are overestimating forest carbon in one region we likely overestimating forest carbon in every region. We worked with Winrock to estimate the degree of correlation among variables – both the correlation of one variable across space as well as the correlation of one variable to any others used in the analysis. This was done by considering dependencies in the underlying data used to estimate each parameter. For example, our forest carbon stock estimates are correlated across Russia because they were derived from one biomass map covering Russia. However, forest carbon stocks in Russia are not correlated with China, because they were derived from separate biomass maps. This partial correlation approach tended to reduce the overall uncertainty associated with GHG emissions factor data.

[172] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 1: General Guidance and Reporting, Chapter 3: Uncertainties, available at http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol1.html

The information about the uncertainty in each parameter and the degree of correlation across parameters was utilized in Monte Carlo analysis to determine the overall uncertainty in our emissions factor estimates. We used the Monte Carlo simulation to combine the emissions factor and satellite data uncertainty for every biofuel scenario analyzed. Uncertainty ranges varied across scenarios depending on the types and locations of land use changes. For example, based on the sources of uncertainty analyzed, the 95% confidence range for land use change emissions (as a percent of the mean) was -27% to +32% for base yield corn ethanol in 2022, and -56% to +76% for base yield soy biodiesel in 2022. [173] More details about this uncertainty analysis are provided in RIA Chapter 2.

iv. *Timeframe of Emission Analysis*

Based on input from the expert peer review and public comments, EPA has chosen to analyze lifecycle GHG emissions using a 30 year time period, over which emissions are not discounted, i.e., a zero discount rate is applied to future emissions. The input we received and the reasons for our use of this approach are described in this section.

As required by EISA, EPA must determine whether biofuels reduce GHG emissions by the required percentage relative to the 2005 petroleum baseline. In the proposal the Agency discussed a number of accounting methods for capturing the full stream of GHG emissions and benefits over time. When accounting for the time profile of lifecycle GHG emissions, two important assumptions to consider are: (1) the time period considered and (2) the discount rate (which could be zero) applied to future emissions streams. At the time of proposal, EPA requested public comment on the choice of time frames and discounting approaches for purposes of estimating lifecycle GHG emissions. Also, as part of the peer review process, EPA requested comment from expert peer reviewers on the choice of the appropriate time frames and discount rates for the RFS2 analysis. Below is a summary of the comments we received on these issues and how we address them in our analytical approach.

Time Period for Analysis: In the proposed rule, EPA highlighted two time periods, 30 years and 100 years, for consideration in our lifecycle analysis. The Agency discussed the relative advantages of these, and other, time periods. In addition, the Agency sought comment on whether it is appropriate to split the time period for GHG emissions assessment based upon how long the biofuel would be produced (i.e., the "project" period) and the time period for which there would likely be GHG emissions changes (i.e., the "impact" period). To encourage expert and public comments on these issues, EPA held public hearings and workshops and sponsored an expert peer review specifically focused on this topic. The expert input and comments that we received included many valuable points which guided our decisions about which time frame should be the focus of our analysis. Below we summarize some of the key arguments made by the peer reviewers and commenters, and how these arguments factored into our choice of analytical approach.

[173] The 95% confidence range indicates there is no more than a 5% chance the actual value is likely to be outside this range.

The expert peer reviewers discussed a number of justifiable time periods ranging from 13 to 100 years for assessing lifecycle GHG emissions. A subset of the reviewers said that EPA's analysis should be restricted to 2010-2022 based on the years specified in EISA, because these reviewers argued that EPA should not assume that biofuel production will continue beyond 2022 at the RFS2 levels. The reviewers said that longer time frames, such as 100 years, were only appropriate if the Agency used positive discount rates to value future emissions. Almost all of the peer reviewers said that a time frame of 20 to 30 years would be a reasonable timeframe for assessing lifecycle GHG emissions. They gave several reasons for why a short time period is appropriate: this time frame is the average life of a typical biofuel production facility; future emissions are less certain and more difficult to value, so the analysis should be confined insofar as possible to the foreseeable future; and a near-term time horizon is consistent with the latest climate science that indicates that relatively deep reductions of heat-trapping gasses are needed to avoid catastrophic changes due to a warming climate. The peer reviewers suggested that while there is no unassailable basis for choosing a precise timeframe the expected average lifetime of a biofuel production facility is the "most sensible anchor" for the choice of a timeframe.

There was support in the public comments for both the 30 year and 100 year time frames. A number of public commenters supported the use of a 30 year time period, or less, and made arguments similar to those of the expert peer reviewers. They argued that shorter time periods give more weight to the known, more immediate, effects of biofuel production and that use of longer time periods gives more weight to activities that are much more uncertain, and that the 100 year timeframe is inappropriate because it is much longer than the life of individual biofuel plants.

On the issue of whether to split the time period for GHG emissions analysis into the "project and "impact" periods, there was little support for the use of a split time frame for evaluating lifecycle GHG emissions by the peer reviewers or in the public comments. The peer reviewers thought that it would be difficult to find a scientific basis for determining the length of the two different time horizons. Also, splitting the time horizon would necessitate consideration of the land use changes following the end of the project time horizon such as land reversion. However, the majority of expert peer reviewers did not think it was appropriate to attribute potential land reversions, following the project time frame, to a biofuel's lifecycle.

Based upon the comments discussed above, EPA has decided to use a 30 year frame for assessing the lifecycle GHG emissions. There are several reasons why the 30 year time frame was chosen. The full life of a typical biofuel plant seems reasonable as a basis for the timeframe for assessing the GHG emissions impacts of a biofuel, because it provides a guideline for how long we can expect biofuels to be produced from a particular entity using a specific processing technology. Also, the 30 year time frame focuses on GHG emissions impacts that are more near term and, hence, more certain. We also determined that longer time periods were less appropriate because the peer reviewers recommended that they should only be used in conjunction with positive discount rates; but, for the reasons discussed below, we are using a zero discount rate in our analysis. In addition, the 30 year time frame is consistent with responses of the peer reviewers that EPA should not split the time periods for analysis, or include potential land reversions following the project time period in the biofuel lifecycle.

Discounting: In the RFS2 Proposal, EPA highlighted two principal options for discounting the lifecycle GHG emission streams from biofuels over time. The first involved the use of a 2% discount rate using the 100 year time horizon for assessing lifecycle GHG emissions streams. The second option involved using a 30 year time horizon for examining lifecycle GHG emissions impacts. In the 30 year case, each GHG emission is treated equally through time, which implicitly assumes a zero discount rate to GHG lifecycle emissions streams. The issue of whether to discount lifecycle GHG emissions was raised as a topic that EPA sought comment on in both the peer review process and in public comments.

EPA received numerous of comments on the issue of whether the Agency should be discounting lifecycle GHG emissions through time. While many of peer reviewers thought that current GHG emissions reductions should be more strongly weighted than future reductions, the peer reviewers were in general agreement that a discount rate should only be applied to a monetary unit, rather than a physical unit, such as GHG emissions. Public commenters suggested that discounting is an essential part of long term cost benefit analysis but it is not necessary in the context of the physical aggregation of lifecycle GHG emissions called for in the EISA. Further, public commenters expressed concerns that any discount rate chosen by the Agency would be based upon relatively arbitrary criteria.

After considering the comments on discounting from the peer review and the public, EPA has decided not to discount (i.e., use a 0% discount rate) GHG emissions due to the many issues associated with applying an economic concept to a physical parameter. First, it is unclear whether EISA intended lifecycle GHG emissions to be converted into a metric whose underpinnings rest on principals of economic valuation. A more literal interpretation of EISA is that EPA should consider only physical GHG emissions. Second, even if the principle of tying GHG emissions to economic valuation approaches were to be accepted, there would still be the problem that there is a lack of consensus in the scientific community about the best way to translate GHG emissions into a proxy for economic damages. Also, there is a lack of consensus as to the appropriate discount rate to apply to GHG lifecycle emissions streams through time. Finally, since EPA has decided to base threshold assessments of lifecycle GHG emissions on a 30 year time frame, the issue of whether to discount GHG emissions is not as significant as if the EPA had chosen the 100 year time frame to assess GHG emissions impacts. More discussion of discount rates and their impact on the lifecycle results can be found in Chapter 2 of the RIA.

v. *GTAP and Other Models*

Although we have used the partial equilibrium (PE) models FASOM and FAPRI-CARD as the primary tools for evaluating whether individual biofuels meet the GHG thresholds, as part of the peer review process, we explicitly requested input on whether general equilibrium (GE) models should be used. None of the comments recommended using a GE model as the sole tool for estimating GHG emissions, given the limited details on the agricultural sector contained in most GE models. The peer reviewers generally supported the use of the FASOM and FAPRI-CARD models for our GHG analysis given the need for additional detail offered in the PE models, however several comments suggested incorporating GE models into the analysis.

Given these recommendations, we opted to use the GTAP model to inform the range of potential GHG emissions associated with land use change resulting from an increase in renewable fuels. As discussed in the NPRM, there are several advantages to using GTAP. As a general equilibrium model, GTAP captures the interaction between different markets (e.g., agriculture and energy) in different regions. It is distinctive in estimating the complex international land use change through trade linkages. In addition, GTAP explicitly models land-use conversion decisions, as well as land management intensification. Most importantly, in contrast to other models, GTAP is designed with the framework of predicting the amount and types of land needed in a region to meet demands for both food and fuel production. The GTAP framework also allows predictions to be made about the types of land available in the region to meet the needed demands, since it explicitly represents different types of land cover within each Agro-Ecological Zone.

Like the peer reviewers, we felt that some of the drawbacks of the GTAP model prevent us from using GTAP as the sole model for estimating GHG emissions from biofuels. As discussed in the NPRM, GTAP does not utilize unmanaged cropland, nor is it able to capture the long-run baseline issues (e.g., the state of the economy in 2022). For our analysis, the GTAP model was most valuable for providing another estimate of the quantity and type of land conversion resulting from an increase in corn ethanol and biodiesel given the competition for land and other inputs from other sectors of the economy. These results were therefore considered as part of the weight of evidence when determining whether corn ethanol or biodiesel met the GHG thresholds.

The quantity of total acres converted to crop land projected by FAPRI-CARD were within the range of values projected by GTAP when normalized on a per BTU basis, although there were differences in the regional distribution of these changes. The land use changes projected by GTAP were smaller than land use changes predicted by FAPRI-CARD, which is primarily due to several important differences in the modeling frameworks. First, the GTAP model incorporates a more optimistic view of intensification options by which higher prices induced by renewable fuels results in higher yields, not just for corn, but also for other displaced crops. Second, the demands for other uses of land are explicitly captured in GTAP. Therefore, when land is withdrawn from these uses, the prices of these products rise and provide a certain amount of “push-back” on the conversion of land to crops from pasture or forest. Third, none of the peer-reviewed versions of GTAP currently contain unmanaged cropland, thereby omitting additional sources of land. Finally, the GTAP model also predicted larger increases in forest conversion than the FAPRI-CARD/Winrock analysis, in part because the GTAP model includes only three types of land (i.e., crops, pasture, forest). As discussed in the FAPRI-CARD/Winrock section, there are many other categories of land which may be converted to pasture and crop land.

As with all economic models, GTAP results are sensitive to certain key parameter values. One advantage of this framework is that it offers a readily usable approach to Systematic Sensitivity Analysis (SSA) using efficient sampling techniques. We have exploited this tool in order to develop a set of 95% confidence intervals around the projected land use changes. Several key parameters were identified that have a significant impact on the land use change projections, including the yield elasticity (i.e., the change in yield that results from a change in that commodity's price), the elasticity of transformation of land supply (i.e., the measure of how easily land can be converted between forest, pasture, and crop land), and the elasticity of transformation of crop land (i.e., the measure of how easily land can be converted between crops). Although the confidence intervals are relatively large, in most cases the ranges do not bracket zero. Therefore, we conclude that the impacts of the corn ethanol and soybean biodiesel mandates on land use change are statistically significant. These confidence intervals also bracket the FAPRI-CARD results. Additional information on the GTAP results is discussed in RIA Chapter 2.

c. Feedstock Transport

To estimate the GHG impacts of transporting corn from the field to an ethanol production facility and transporting the co-product DDGS from the ethanol facility to the point of use, we used the method described in the proposed rule. We also did not change our estimates for the transport of cellulosic biofuel feedstock and biomass-based diesel feedstock.

For sugarcane transport, we received the comment that the GREET defaults used to estimate the energy consumption and associated GHG emissions do not all reflect current industry practices. To address this concern, we reviewed the current literature on sugarcane transport and updated our assumptions on the distance sugarcane travels by truck from the field to ethanol production facilities as well as the payload and fuel economy of those trucks. We incorporated these revised inputs into an updated version of the GREET model (Version 1.8c) in order to estimate the GHG impacts of sugarcane transport. More details on these updates can be found in Chapter 2 of the RIA.

In the proposal, we discussed updating our analysis to incorporate the results of a recent study detailing biofuel production locations and modes of transport. This study, conducted by Oak Ridge National Laboratory, modeled the transportation of ethanol from production or import facilities to petroleum blending terminals. Since the study did not explicitly address the transport of biofuel feedstocks, we did not implement the results for this part of the analysis. However, we did incorporate the results into our assessment of the GHG impacts of fuel transportation. We will continue to examine whether our feedstock transport estimates could be significantly improved by implementing more detailed information on the location of biofuel production facilities.

We also discussed updating the transportation modes and distances assumed for corn and DDGS to account for the secondary or indirect transportation impacts. For example, decreases in exports will reduce overall domestic agricultural commodity transport and emissions but will increase transportation of commodities internationally. We did not implement these secondary transportation impacts in this final rule. While we do not anticipate that such impacts would significantly change the lifecycle analysis, we plan to continue to look at this issue and consider incorporating them in the future.

d. Biofuel Processing

For the proposal the GHG emissions from renewable fuel production were calculated by multiplying the Btus of the different types of energy inputs at biofuel process plants by emissions factors for combustion of those fuel sources. The Btu of energy input was determined based on analysis of the industry and specific work done as part of the NPRM. The emission factors for the different fuel types are from GREET and were based on assumed carbon contents of the different process fuels. The emissions from producing electricity in the U.S. were also taken from GREET and represent average U.S. grid electricity production emissions.

We received comments on our approach and updated the analysis of GHG emissions from biofuel process for the final rule specifically regarding process energy use and the treatment of co-products.

Process Energy Use: For the final rule we updated each of our biofuel pathways to include the latest data available on process energy use. For the proposal, one of the key sources of information on energy use for corn ethanol production was a study from the University of Illinois at Chicago Energy Resource Center. Between proposal and final rule, the study was updated, therefore, we incorporated the results of the updated study in our corn ethanol pathways process energy use for the final rule. We also updated corn ethanol production energy use for different technologies in the final rule based on feedback from industry technology providers as part of the public comment period. The main difference between proposal and final corn ethanol energy use values was a slight increase in energy use for the corn ethanol fractionation process, based on feedback from industry technology providers.

For the proposal we based biodiesel processing energy on a process model developed by USDA-ARS to simulate biodiesel production from the Fatty Acid Methyl Ester (FAME) transesterification process. We received a number of comments from stakeholders that the energy balance for biodiesel production was overestimating energy use and should be updated. During the comment period USDA updated their energy balance for biodiesel production to incorporate a different biodiesel dehydration process based on a system which has resulted in a decrease in energy requirements. This change was reflected in the energy use values for biodiesel assumed in our final rule analysis which resulted in reduced GHG impacts from the biodiesel production process.

In addition, for the final rule we have included an analysis of algae oil production for biodiesel based on ASPEN process modeling from NREL.[174] The analysis is for two major cultivation pathways (open pond and photobioreactors) for a facility that can be feasibly commercialized in the future, represented by a "2022" target production. We coupled the algae oil production process (which includes cultivation, harvesting, and extraction) with the biodiesel production energy use from virgin oils energy use model under the assumption that algae oil is similar enough to that of virgin oil.

For the cellulosic biofuel pathways, we updated our final rule energy consumption assumptions on process modeling also completed by NREL. For the NPRM, NREL estimated energy use for the biochemical enzymatic process to ethanol route in the near future (2010) and

[174] Davis, Ryan. November 2009. Techno-economic analysis of microalgae-derived biofuel production. National Renewable Energy Laboratory (NREL)

future (2015 and 2022).[175,176,177] As there are multiple processing pathways for cellulosic biofuel, we have expanded the analysis for the FRM to also include thermochemical processes (Mixed-Alcohols route and Fischer-Tropsch to diesel route) for plants which assume woody biomass as its feedstock.

Under the imported sugarcane ethanol cases we updated process energy use assumptions to reflect anticipated increases in electricity production for 2022 based on recent literature and comments to the proposal. One major change was assuming the potential use of trash (tops and leaves of sugarcane) collection in future facilities to generate additional electricity. The NPRM had only assumed the use of bagasse for electricity generation. Based on comments received, we are also assuming marginal electricity production (i.e., natural gas) instead of average electricity mix in Brazil which is mainly hydroelectricity. This approach assumes surplus electricity will likely displace electricity which is normally dispatched last, in this case typically natural gas based electricity. The result of this change is a greater credit for displacing marginal grid electricity and thus a lower GHG emissions profile for imported sugarcane ethanol than that assumed in the NPRM. We also received public comment that there are differences in the types of process fuel e.g. used in the dehydration process for ethanol. While using heavier fuels such as diesel or bunker fuel tends to increase the imported sugarcane ethanol emissions profile, the overall impact was small enough that lifecycle results did not change dramatically.

Co-Products: In response to comments received, we included corn oil fractionation and extraction as a potential source of renewable fuels for this final rulemaking. Based on research of various corn ethanol plant technologies, corn oil as a co-product from dry mill corn ethanol plants can be used as an additional biodiesel feedstock source (see Section VII.A.2 for additional information). Dry mill corn ethanol plants have two different technological methods to withdraw corn oil during the ethanol production process. The fractionation process withdraws corn oil before the production of the DGS co-product. The resulting product is food-grade corn oil. The extraction process withdraws corn oil after the production of the DGS co-product, resulting in corn oil that is only suitable for use as a biodiesel feedstock.

Based on cost projections outlined in Section VII.A, it is estimated that by 2022, 70% of dry mill ethanol plants will conduct extraction, 20% will conduct fractionation, and that 10% will choose to do neither. These parameters have been incorporated into the FASOM and FAPRI-CARD models for the final rulemaking analysis, allowing for corn oil from extraction as a major biodiesel feedstock.

Glycerin is a co-product of biodiesel production. Our proposal analysis did not assume any credit for this glycerin product. The assumption for the proposal was that by 2022 the market for glycerin would be saturated due to the large increase in biodiesel production in both the US and abroad and the glycerin would therefore be a waste product. We received a number

[175] Tao, Ling and Aden, Andy. November 2008. Techno-economic Modeling to Support the EPA Notice of Proposed Rulemaking (NOPR). National Renewable Energy Laboratory (NREL)
[176] Aden, Andy. September 2009. Mixed Alcohols from Woody Biomass – 2010, 2015, 2022. National Renewable Energy Laboratory (NREL)
[177] Davis, Ryan. August 2009. Techno-economic analysis of current technology for Fischer-Tropsch fuels. National Renewable Energy Laboratory (NREL)

of comments that we should be factoring in a co-product credit for glycerin as there would be some valuable use for this product in the market. Based on these comments we have included for the final rule analysis that glycerin would displace residual oil as a fuel source on an energy equivalent basis. This is based on the assumption that the glycerin market would still be saturated in 2022 and that glycerin produced from biodiesel would not displace any additional petroleum glycerin production. However, the biodiesel glycerin would not be a waste and a low value use would be to use the glycerin as a fuel source. The fuel source assumed to be replaced by the glycerin is residual oil. This inclusion of a co-product credit for glycerin reduces the overall GHG impact of biodiesel compared to the proposal analysis.

e. Fuel Transportation

For the proposed rule, we estimated the GHG impacts associated with the transportation and distribution of domestic and imported ethanol and biomass-based diesel using GREET defaults. We have upgraded to the most recent version of GREET (Version 1.8c) for our transportation analysis in the final rule[178]. We made several other updates to the method we utilized in the proposed rule. These updates are described here and in more detail in Chapter 2 of the RIA.

In the proposal, we noted our intention to incorporate the results of a recent study by Oak Ridge National Laboratory (ORNL) into our transportation analysis for the final rule. The ORNL study models the transportation of ethanol from refineries or import facilities to the petroleum blending terminals by domestic truck, marine, and rail distribution systems. We used ORNL's transportation projections for 2022 under the EISA policy scenario to update our estimates of the GHG impacts associated with the transportation of corn, cellulosic, and sugarcane ethanol. Since the study did not address the distribution of ethanol from petroleum blending terminals to refueling stations, we continued to use GREET defaults to estimate these impacts.

The ORNL study also did not address the transportation of imported ethanol within its country of origin or en route to the import facility in the United States. As in the proposal, we used GREET defaults to estimate the impacts associated with the transportation of sugarcane ethanol within Brazil. We updated the GREET default for the average distance sugarcane ethanol travels by ocean tanker using recent shipping data from EIA in order to account for both direct Brazilian exports and the shipment of ethanol from countries in the Caribbean Basin Initiative. We received several comments on the back-haul emissions associated with ocean transport. For the final rule, we assumed that these emissions were negligible.

f. Vehicle Tailpipe Emissions

We updated the CO_2 emissions factors for ethanol and biodiesel to be consistent with those used in the October 30, 2009 final rulemaking for the Mandatory GHG Reporting Rule. These changes caused the tailpipe GHG emission factors to increase by 0.8% for ethanol and to decrease by 1.5% for biodiesel. Specific tailpipe combustion values used in this final rule can be

[178] The method used to estimate the GHG impacts associated with biodiesel transportation has not been changed since the proposal. This method utilized an earlier version of the GREET model.

found in Chapter 2of the RIA. Estimates for CH_4 and N_2O were made using outputs from EPA's MOVES model.

3. Petroleum Baseline

For the proposed rule, we conducted an analysis to determine the lifecycle greenhouse gas emissions for the petroleum baseline against which renewable fuels were to be compared. We utilized the GREET model (Version 1.8b), which uses an energy efficiency metric to calculate GHG emissions associated with the production of petroleum-based fuels. We received numerous comments regarding this approach.

Petroleum baseline calculation from proposed rule: The GREET model relies on using average values as inputs to estimate aggregate emissions, rather than using site-specific values. Commenters noted a number of GREET input values that they believed to be incorrect. These included: energy efficiency values for crude oil extraction; methane emission factors for oil production and flaring; transportation distances for crude oil and petroleum products; and the oil tanker cargo payload value. Commenters also noted that GREET does not account for the energy consumption associated with crude oil transport in the country of extraction.

In addition, commenters stated that the crude oil import slate assumed in the proposed rule was inconsistent with EIA crude oil production and import data for 2005. Commenters also noted that the gasoline and diesel mix that we used for the proposal did not match with EIA prime supplier sales volume data. One specific comment focused on the definition of low-sulfur diesel in GREET, where it is defined as being 11 ppm sulfur content, which is inconsistent with EPA's definition. As a result, in the proposed rule, all transportation diesel produced in 2005 was assumed to be ultra-low sulfur diesel.

We largely agree with the above comments. An updated version of the GREET model (Version 1.8c) is available, and it may address some of the issues raised by commenters. We considered using this new version of GREET with updated input values from publically available sources to determine the petroleum baseline for the final rule. However, we have decided that using the 2005 petroleum baseline model developed by the National Energy Technology Laboratory (NETL)[179] would address the commenters' concerns, and result in a more accurate and comprehensive assessment of the petroleum baseline than we could obtain using the GREET model.

Use of NETL study for final rule petroleum baseline calculation: In the proposed rule, we requested comment on using the NETL study for our 2005 petroleum baseline for the final rulemaking. We only received one comment, which agreed that the NETL values were generally more accurate and better documented than the values in GREET. However, the commenter also stated that NETL's use of 2002 crude oil extraction data would underestimate extraction emissions for 2005, and that it would be inconsistent to use the GREET model for determining GHG emissions from biofuels, but not for petroleum.

[179] Department of Energy: National Energy Technology Laboratory. 2009. NETL: Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis - 2005 Baseline Model.

We do not agree with the commenters' criticism of the NETL model. We have not seen data that indicates that the GHG emissions associated with crude oil extraction would be appreciably different in 2005 than 2002. EPA also believes that it is important to use the best available tools to estimate a petroleum baseline that can be compared to renewable fuels. The fact that some GREET emission factors are used in the calculation of biofuel lifecycle GHG impacts is not a reason to use the GREET model for the petroleum baseline analysis over what we feel to be a better tool for the baseline calculation needed.

NETL states that the goal of their study is to "determine the life cycle greenhouse gas emissions for liquid fuels (conventional gasoline, conventional diesel, and kerosene-based jet fuel) production from petroleum as consumed in the U.S. in 2005 to allow comparisons with alternative transportation fuel options on the same basis (i.e., life cycle modeling assumptions, boundaries, and allocation procedures)." Unlike GREET, the NETL study utilized site-specific data, such as country-specific crude oil extraction profiles and port-to-port travel distances for imported crude oil and petroleum products. The NETL model also accounts for NGLs and unfinished oils as refinery inputs, which is not available in GREET.

Thus, we believe that use of the NETL model addresses the commenters' concerns with the GREET inputs used in the proposed rule. We have also verified that the NETL model uses a crude oil input mix and gasoline and diesel product slate consistent with EIA data for 2005.

For the final rule, we have also updated the CO_2 emissions factors to be consistent with other EPA rulemakings. EPA recently revised the CO_2 emission factors for gasoline and diesel and used them in the September 28, 2009 proposed rule to establish GHG standards for light-duty vehicles. These new factors are slightly lower than those used in the RFS2 proposal and result in a decrease in tailpipe GHG emissions of 0.4% for gasoline of 0.6% and for diesel.

Overall, with the switch to NETL and the updated tailpipe values, the final petroleum baseline value calculated for the final rule analysis does not differ significantly from what we calculated in the proposed rule.

<u>Inclusion of estimate for land use change</u>: Numerous commenters raised the issue of land use change with regard to oil production, both on a direct and indirect basis. The proposed rule analysis for baseline petroleum emissions did not consider any land use change emissions associated with crude oil extraction. For the final rule, we do not consider land use emissions associated with road or other infrastructure construction for petroleum extraction, transport, refining, or upgrading, as the land use change associated with roads constructed for crop and livestock production was also not included. Furthermore, land use associated with natural gas extracted for use in oil sands extraction or upgrading was also not considered, as the land use change from natural gas extracted for biofuels production was not considered.

However, for the final rule we did consider the inclusion of land use emissions associated with oil extraction. Using estimates for land-use change from conventional oil production and oil sands in conjunction with our data for the carbon intensity of land being developed, we were able to determine GHG emissions associated with land use change for oil production. Our analysis showed that the value was negligible compared to the full petroleum lifecycle. More detail on this analysis can be found in Chapter 2 of the RIA.

Consideration of marginal impacts: We received several comments stating that we did not use consistent system boundaries in our comparisons of biofuels and petroleum-based fuels, in particular by using a marginal assessment of GHG emissions related to biofuel, but not doing so for baseline petroleum fuels. According to commenters, by not assessing the marginal impacts of petroleum production, we overestimated the GHG impacts of an increase in biofuel use in the proposed rule. Commenters argued that a consistent modeling approach would involve a marginal analysis for both biofuels and the petroleum baseline.

The reason the system boundaries used for threshold assessment in the proposed rule and the final rule did not include a marginal analysis of petroleum production was due to the definition of "baseline lifecycle greenhouse gas emissions" in Section 211(o)(1)(C) of the CAA. The definitions of the different renewable fuel categories specify that the lifecycle threshold analysis be compared to baseline lifecycle greenhouse gas emissions, which are defined as:

> The term 'baseline lifecycle greenhouse gas emissions' means the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.

Therefore, the petroleum production component of the system boundaries is specifically mandated by EISA to be based on the 2005 average for crude oil used to make gasoline or diesel sold or distributed as transportation fuel, and not the marginal crude oil that will be displaced by renewable fuel. Furthermore, as the EISA language specifies that the baseline emissions are to be only "average" lifecycle emissions for this single specified year and volume, it does not allow for a comparison of alternative scenarios. Indirect effects can only be determined using such an analysis; therefore there are no indirect emissions to include in the baseline lifecycle greenhouse gas emissions.

On the other hand, assessing the lifecycle GHG emissions of renewable fuel is not tied by statute to the 2005 baseline and could therefore be based on a marginal analysis of anticipated changes in transportation fuel as would result from meeting the EISA mandates.

Thus, Congress did not, as many commenters suggested, intend to accomplish simply a reduction in GHG emissions as compared to the situation that would exist in the future without enactment of EISA, as would be the case if Congress had specified that EPA use a marginal analysis in assessing the GHG emissions related to conventional baseline fuels that the EISA-mandated biofuels would replace Rather, the statute specifies a logical approach for reducing the GHG emissions of transportation fuel as compared to those emissions that occurred in 2005. Therefore, EPA has retained in today's final rule the basic analytical approach (marginal analysis for biofuels and 2005 average for baseline fuels) used in the proposed rule.

C. Threshold Determination and Assignment of Pathways

As required by EISA, EPA is making a determination of lifecycle GHG emission threshold compliance for the range of pathways likely to produce significant volumes of biofuel for use in the U.S. by 2022. These threshold assessments only pertain to biofuels which are not produced in production facilities that are grandfathered (grandfathering of production facilities is discussed at the end of Section V.C).

As described in Section I.A.3, because of the inherent uncertainty and the state of the evolving science on this issue, EPA is basing its GHG threshold compliance determinations for this rule on an approach that considers the weight of evidence currently available. For fuel pathways with a significant land use impact, the evidence considered includes the best estimate as well as the range of possible lifecycle greenhouse gas emission results based on formal uncertainty and sensitivity analyses conducted by the Agency. In making the threshold determinations for this rule, EPA weighed all of the evidence available to it, while placing the greatest weight on the best estimate value for the base yield scenario. In those cases where the best estimate for the potentially conservative base yield scenario exceeds the reduction threshold, EPA judges that there is a good basis to be confident that the threshold will be achieved and is determining that the bio-fuel pathway complies with the applicable threshold. To the extent the midpoint of the scenarios analyzed lies further above a threshold for a particular biofuel pathway, we have increasingly greater confidence that the biofuel exceeds the threshold.

EPA recognizes that the state of scientific knowledge in this area is continuing to evolve, and that as the science evolves, the lifecycle greenhouse gas assessments for a variety of fuel pathways will continue to change. Therefore, while EPA is making regulatory determinations for fuel pathways as required by the statute in this final rule based on its current assessment, EPA is at the same time committing to further reassess these determinations and the lifecycle estimates. As part of the ongoing effort, we will ask for the expert advice of the National Academy of Sciences as well as other experts and then reflect this advice and any updated information in a new assessment of the lifecycle GHG emission performance of the biofuels being evaluated today. EPA will request that the National Academy of Sciences evaluate the approach taken in this rule, and the underlying science of lifecycle assessment and in particular indirect land use change, and make recommendations for subsequent rulemakings on this subject. This new assessment could in some cases result in new determinations of threshold compliance compared to those included in this rule which would apply to future production from plants that are constructed after each subsequent rule.

Nonetheless, EPA is required by EISA to make threshold determinations at this time as to what fuels qualify for each of the four different fuel categories and lifecycle GHG thresholds. In the previous sections, we have described the analytical basis EPA is using for its lifecycle GHG assessment. These analyses represent the most up to date information currently available on the GHG emissions associated with each element of the full lifecycle assessment. Notably these analyses include an assessment of uncertainty for key parameters of the pathways evaluated. The best estimates and ranges of results for the different pathways can be used to help assess whether a particular pathway should be considered as attaining the 20%, 50% or 60% thresholds, as applicable. The graphs included in the discussion below provide representative depictions of the results of our analysis (including the uncertainty in the modeling) for typical pathways for corn ethanol, biodiesel produced from soy oil and from waste oils, fats and greases, sugarcane ethanol and cellulosic biofuel from switchgrass. We have also conducted lifecycle modeling assessments for cellulosic biofuel pathways using other feedstock sources, for biobutanol and for two specific pathways for emerging biofuels that would use oil from algae as their feedstock. Additional GHG performance assessment results for other feedstock/fuel/technology combinations are also described below as well as in the RIA Chapter 2.

Below we consider the analytical results of scenarios and fuel pathways modeled by EPA as well as additional appropriate information to determine the threshold compliance for an array of biofuels likely to be produced in 2022.

Ethanol from corn starch: While EPA analyzed the lifecycle GHG performance of a variety of ethanol from corn starch pathways (complete results can be found in the RIA), for purposes of this threshold determination we have focused the discussion on the impacts of those plant designs that are most likely to be built in the future. We have focused this discussion on new plant designs because production from existing plants is grandfathered for purposes of compliance with the 20% lifecycle GHG threshold. Only new plants and expanded capacity at existing plants need to comply with a 20% lifecycle GHG emissions threshold to comply with the total renewable fuel mandate under the RFS2.

While we focus our lifecycle GHG threshold analysis on the new plant designs most likely to be built through 2022, we also note that some existing plant designs, although subject to the grandfathering provisions, would not qualify if having to meet the 20% performance threshold. For example, existing designs of ethanol plants using coal as their process heat source would not qualify.

As discussed in Section IV, EPA anticipates that by 2022 any new dry mill plants producing ethanol from corn starch will be equipped with more energy efficient technology and/or enhanced co-product production than today's average plant. These predictions are largely based on economic considerations. To compete economically, future ethanol plants will need to employ energy saving technologies and other value added technologies that have the effect of also reducing their GHG footprint. For example, while only in limited use today, we predict approximately 90% of all plants will be producing corn oil as a by-product either through a fractionation or extraction process; it is likely most if not all new plants will elect to include such technology. We also predict that all will use natural gas, biomass or biogas as the process energy source.[180] [181] We also expect that, to lower their operating costs, most facilities will sell a

[180] Dry mill corn ethanol plants using coal as a process energy source would not qualify as exceeding the 20% reduction threshold as modeled. We do not expect plants relying on coal for process energy to be built through 2022. However, if they were built, they would need to use technology improvements such as carbon capture and storage (CCS) technology. We did not model what the performance would be if these plants also installed CCS technology.

[181] We believe do not believe new wet mill corn ethanol plants will be built through 2022 since this design is much more complicated and expensive than a dry mill plant. Especially since dry mill plants equipped with corn oil fractionation will produce additional supplies of food grade corn oil (one of the products and therefore reasons to construct a wet mill plant), we see no near term incentive for additional wet mill ethanol production capacity. However, we have modeled the lifecycle GHG impact of ethanol produced at a wet mill plant when relying on biomass as the process energy source and have determined it would meet the 20% GHG threshold. Therefore, this type of facility is also included in Table V.C-6.

portion of their co-product DGS prior to drying thus reducing energy consumption and improving the efficiency and lifecycle GHG performance of the plant. The current national average plant sells approximately 37% of the DGS co-product prior to drying.

In analyzing the corn ethanol plant designs we expect could be built through 2022 using natural gas or biomass for process energy and employing advanced technology, in all cases, the midpoint and therefore the majority of the scenarios analyzed are above the 20% threshold. This indicates that, based on the current modeling approaches and sets of assumptions, we are over 50% confident the actual GHG performance of the ethanol from new corn ethanol plants will exceed the threshold of 20% improvement in lifecycle GHG emissions performance compared to the gasoline it is replacing.

We are determining at this time that the corn ethanol produced at such new plants (and existing plants with expanded capacity employing the same technology) will exceed the 20% GHG performance threshold. A complete listing of complying facilities using advanced technologies and operating procedures is included in Table V.C-6.

Figure V.C-1 shows the percent change in the lifecycle GHG emissions compared to the petroleum gasoline baseline in 2022 for a corn ethanol dry mill plant using natural gas for its process energy source, drying the national average of 63% of the DGS it produces and employing corn oil fractionation technology. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 20% reduction threshold is represented by the dashed line at -20 on the graph. The results for this corn ethanol scenario are that the midpoint of the range of results is a 21% reduction in GHG emissions compared to the gasoline 2005 baseline. The 95% confidence interval around that midpoint ranges from a 7% reduction to a 32% reduction compared to the gasoline baseline.

Figure V.C-1
Distribution of Results for a New Natural Gas Fired Corn Ethanol Plant
Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)

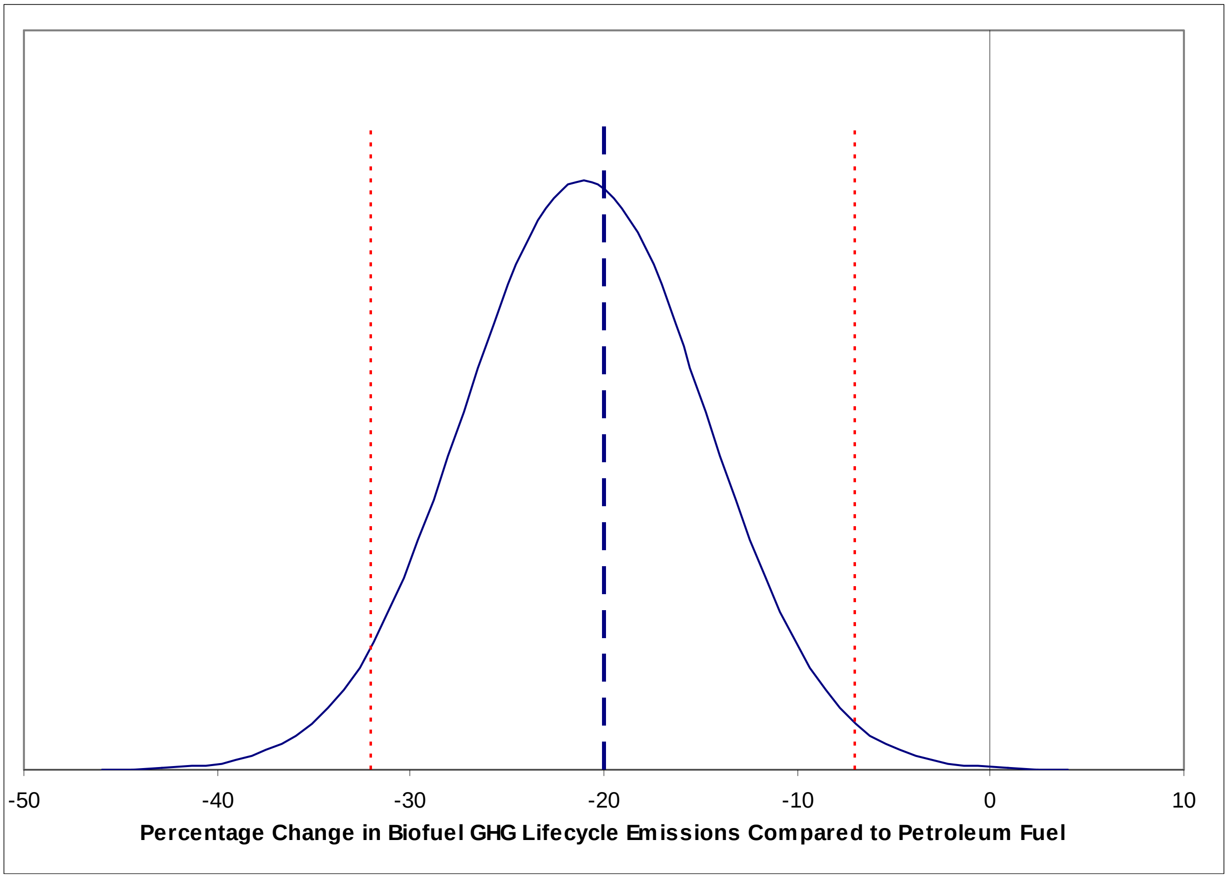


Table V.C-1 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for a natural gas dry mill corn ethanol facility as compared to the 2005 baseline average for gasoline. This table (and similar tables which follow in the discussion for other biofuels) is included to transparently demonstrate the contribution of each stage and their relative significance. Lifecycle emissions are normalized per energy unit of fuel produced and presented in kilograms of carbon-dioxide equivalent GHG emissions per million British Thermal Units of renewable fuel produced (kg CO_2e/mmBTU). The domestic and international agriculture rows include emissions from changes in agricultural production (e.g., fertilizer and energy use, rice methane) and livestock production. The fuel production row includes emissions from the fuel production or refining facility, primarily from energy consumption. For renewable fuels, tailpipe emissions only include non- CO_2 gases, because the carbon emitted as a result of fuel combustion is offset by the uptake of biogenic carbon during feedstock production. Note, that while the table separates the emissions into different categories, the results are based on integrated modeling; therefore, one component can not be removed without impacting the other results. For example, domestic land use and agricultural sector emissions depend on the international assumptions. If a case without international impacts were modeled, the domestic results would likely be significantly different.

The table includes our mean estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions. The last row includes mean, low and high total lifecycle GHG emissions based on the 95% confidence range for land use change emissions. For the petroleum baseline, the fuel production stage includes emissions from extraction, transport, refining and distribution of petroleum transportation fuel. Petroleum tailpipe emissions include CO_2 and non- CO_2 gases emitted from fuel combustion.

Table V.C-1
Lifecycle GHG Emissions for Corn Ethanol, 2022
(kg CO_2e/mmBTU)

Fuel Type	Ethanol	2005 Gasoline Baseline
Fuel Production Technology	Natural Gas Fired Dry Mill	
Net Domestic Agriculture (w/o land use change)	4	
Net International Agriculture (w/o land use change)	12	
Domestic Land Use Change	-2	
International Land Use Change, Mean *(Low/High)*	32 *(21/46)*	
Fuel Production	28	19
Fuel and Feedstock Transport	4	
Tailpipe Emissions	1	79

Total Emissions, Mean *(Low/High)*	**79 *(54/97)***	**98**

While we are projecting technology enhancements which would allow corn ethanol plants to exceed the threshold, plant designs which do not included such advance technology would not comply. For example, a basic plant which is not equipped with combinations of advanced technologies such as corn oil fractionation or dries more than 50% of its DGS is predicted to not comply. While we do not expect such a basic, low technology plant to be built nor existing plants to expand their production without also installing such advanced technology, if this were to occur, ethanol produced at such facilities would not comply with the 20% threshold.

Biodiesel from soybean oil: We analyzed the lifecycle GHG emission impacts of producing biodiesel using soy oil as a feedstock for compliance with a lifecycle GHG performance threshold of 50%. The modeling framework for this analysis was much the same as used for the proposal. However, as noted above, based on comments, updated information and enhanced models, the results are significantly updated.

As in the case of ethanol produced from corn starch, EPA has relied on a weight of evidence in developing its threshold assessment for biodiesel produced from soybean oil. In analyzing the base yield case, the midpoint and therefore the majority of the scenarios analyzed exceed the threshold. This indicates that based on currently available information and our current analysis over the range of scenarios considered, the actual performance of soy oil-based biodiesel likely exceeds the applicable 50% threshold.

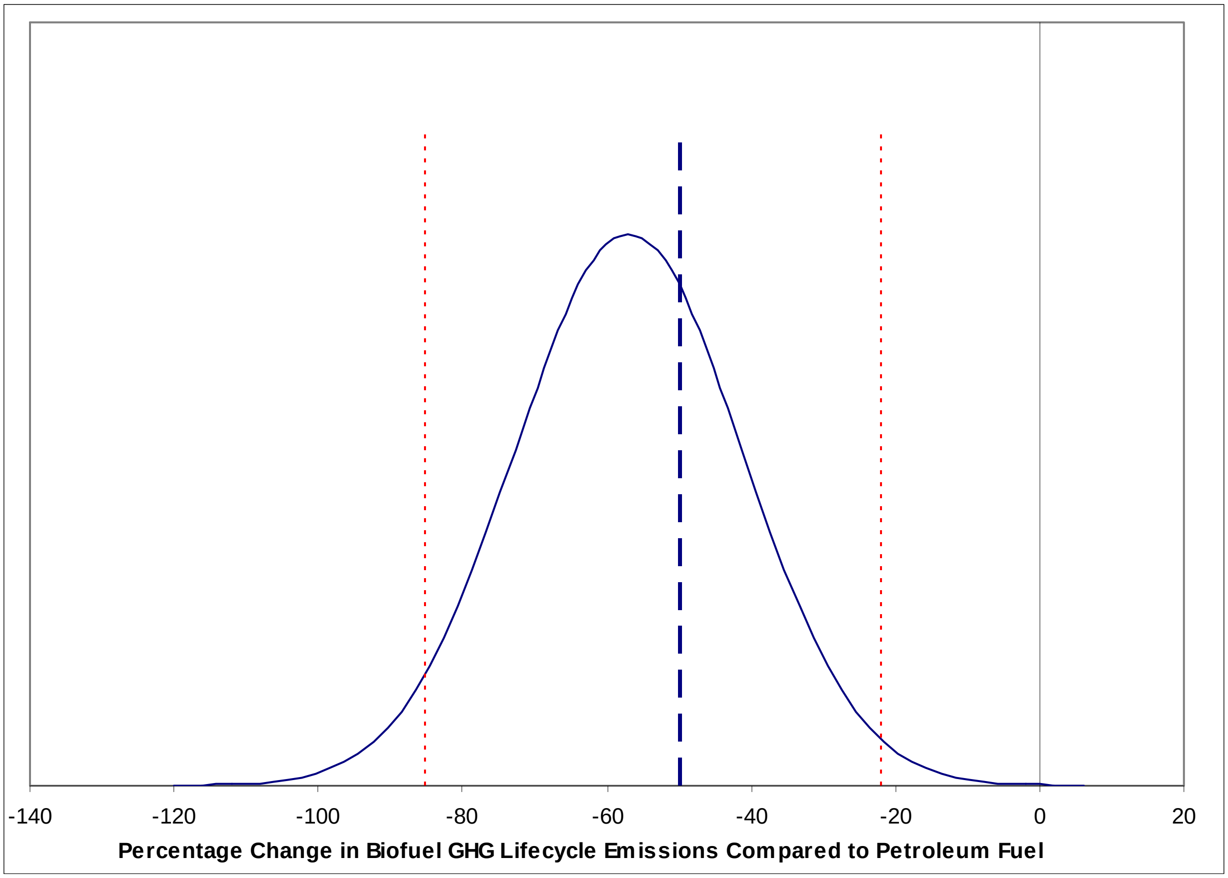
The scenarios analyzed also indicate, based on current data, we are at least 95% confident biodiesel produced from soy oil will have GHG impacts which are better than the 2005 baseline diesel fuel. From a GHG impact perspective, we therefore conclude that even in the less likely event the actual performance of biodiesel from soy oil does not exceed the 50% threshold, GHG emission performance of transportation fuel would still improve if this biodiesel replaced diesel fuel.

We are further confident that biodiesel exceeds the 50% threshold since our assessment of biodiesel GHG performance does not include any prediction of significant improvements in plant technology or unanticipated energy saving improvements that would further improve GHG performance. Additionally, our assumption that the co-product of glycerin would only have GHG value as replacement for residual heating oil could be conservative. While we have not analyzed the range of potential uses of glycerin, potential uses of glycerin including as a feedstock to the chemical industry could be higher in GHG benefit than its assumed use as a heating fuel.

Considering all of the above current information and analyses, EPA concludes that biodiesel made from soy oil will exceed its lifecycle GHG threshold. Further, we see no benefit in lowering the threshold to as low as 40% as allowed under EISA as this will neither benefit available supply nor GHG performance of the fuel. Therefore, the threshold for this rule will be maintained at 50%.

Figure V.C-2 shows the percent change in the typical 2022 soybean biodiesel lifecycle GHG emissions compared to the petroleum diesel fuel 2005 baseline. Lifecycle GHG emissions equivalent to the diesel fuel baseline are represented on the graph by the zero on the X-axis. The 50% reduction threshold is represented by the dashed line at -50 on the graph. The results for soybean biodiesel are that the midpoint of the range of results is a 57% reduction in GHG emissions compared to the diesel fuel baseline. The 95% confidence interval around that midpoint results in range of a 22% reduction to an 85% reduction compared to the diesel fuel 2005 baseline.

Figure V.C-2
Distribution of Results Soybean Biodiesel
Average 2022 plant; natural gas



Biodiesel from waste oils, fats and greases: The lifecycle assessment of GHG performance for biodiesel produced from waste oils, fats and greases is much simpler than comparable assessments for biofuels made from crops. In the case of biodiesel made from waste material, there is no land use impact so the agricultural assessments required for crop-based biofuels are unnecessary. Without the uncertainty concerns due to land use impacts, there was no need to conduct an uncertainty analysis for biodiesel from waste oils, fats and greases. The assessment methodology for biofuel from waste oils fats and greases is much the same as that analyzed for the proposal. As was the case for the proposal, the assessment of each element in the lifecycle process is straight forward and includes collecting and transporting the feedstock, transforming it into a biofuel and distributing and using the fuel. Based on the lifecycle assessment for this final rule, we are estimating biofuel from waste oils, fats and greases result in an 86% reduction in GHG emissions compared to the 2005 baseline for petroleum diesel. As was the case for the assessment included in the proposal, biofuel from these feedstock sources easily exceeds the applicable threshold of 50%.

Table V.C-2 below breaks down by stage the lifecycle GHG emissions for soy-based biodiesel, biodiesel from waste grease feedstocks and the 2005 diesel baseline. The average 2022 biodiesel production process reflected in this table assumes that natural gas is used for process energy and accounts for co-product glycerin displacing residual oil. This table demonstrates the contribution of each stage and their relative significance.

Table V.C-2
Lifecycle GHG Emissions for Biodiesel, 2022
(kg CO_2e/mmBTU)

Fuel Type	Soy-Based Biodiesel	Waste Grease Biodiesel	2005 Diesel Baseline
Net Domestic Agriculture (w/o land use change)	-10 0		
Net International Agriculture (w/o land use change)	1 0		
Domestic Land Use Change	-9	0	
International Land Use Change, Mean *(Low/High)*	43 *(15/76)*	0	
Fuel Production	13	10	18
Fuel and Feedstock Transport	3	3	
Tailpipe Emissions	1	1	79
Total Emissions, Mean *(Low/High)*	42 *(14/76)*	14 97	

Biodiesel from algae oil: We analyzed the lifecycle GHG emission impacts of producing biodiesel from algae oil as a feedstock for compliance with a lifecycle performance threshold of 50%. Our analyses were based on technoeconomic modeling completed by NREL, as previously discussed. The NREL modeling included algae cultivation, harvesting, extraction, and recover of algae oil. Algae oil is further assumed to use the same oil to biodiesel production technology as soy oil, which was updated based on enhanced models. As algae are expected to be grown on relatively small amounts of non-arable lands, it is expected that the land use impact will be negligible. Based on our current lifecycle assessment of algae oil for the final rule, we are determining that biodiesel from algae oil will comply with the lifecycle performance advanced biofuel threshold of 50%.

Ethanol from sugarcane: As is the case for other crop-based biofuels, EPA considered the weight of evidence currently available information in assessing the lifecycle GHG performance of this fuel. As noted in Section I.A.3, this lifecycle GHG assessment includes significant updates from the analysis performed for the proposal. We have added pathways for sugarcane ethanol such that we now distinguish sugarcane ethanol produced assuming most crop residue (leaves and stalks) are collected and therefore available for burning as process energy, or sugarcane produced without the extra crop residue being collected nor burned as process energy. We also analyzed pathways assuming the ethanol is distilled in Brazil or alternatively being distilled in the Caribbean. We did not analyze a "high yield" case for sugarcane as we did for corn and soy since we had no information available suggesting there could be an appreciable range in expected sugarcane yields.

Based on the currently available information, the midpoint and thus the majority of the scenarios analyzed exceed the 50% threshold applicable to advanced biofuels. This indicates that based on currently available information and our current analysis, it is more than 50% likely that the actual performance of ethanol produced from sugarcane exceeds the applicable 50% threshold.

The analyses also indicate, based on current data, ethanol produced from sugarcane will clearly have GHG impacts which are better than the 2005 baseline gasoline. From a GHG impact perspective, we therefore conclude that even in the less likely event the actual performance of sugarcane does not exceed the 50% threshold, GHG emission performance of ethanol from sugarcane would be better than gasoline.

We also considered what would happen if we determine that ethanol from sugarcane does not comply with a 50% threshold due to the relatively low risk that this biofuel will actually be below that threshold. Based on our current analysis of available pathways for producing advanced biofuel, we believe that it will be necessary to include over 2 billion gallons of sugarcane ethanol in order to meet the advanced biofuel volumes anticipated by EISA. If sugarcane ethanol was not an eligible source of advanced biofuel and other unanticipated sources did not become available, the standard for advanced biofuel would have to be lower to the extent necessary to compensate for the lack of eligible sugarcane ethanol. The lower amount of advanced biofuel would then most likely be replaced with petroleum-based gasoline. The replacement fuel would have a worse GHG performance than the sugarcane ethanol. Therefore, GHG performance of the transportation fuel pool would suffer.

Considering the above, EPA has concluded that, based on currently available information and our analysis, ethanol from sugarcane qualifies as an advanced biofuel.

Figure V.C-3 shows the percent change in the average 2022 sugarcane ethanol lifecycle GHG emissions compared to the petroleum gasoline 2005 baseline. These results assume the ethanol is produced and dehydrated in Brazil prior to being imported into the U.S. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 50% reduction threshold is represented by the dashed line at -50 on the graph. The results for this sugarcane ethanol scenario are that the midpoint of the range of results is a 61% reduction in GHG emissions compared to the gasoline baseline. The 95% confidence interval around that midpoint results in a range of a 52% to 71% reduction compared to the gasoline 2005 baseline.

Figure V.C-3
Distribution of Results for Sugarcane Ethanol
Average 2022 plant: no residue collection,

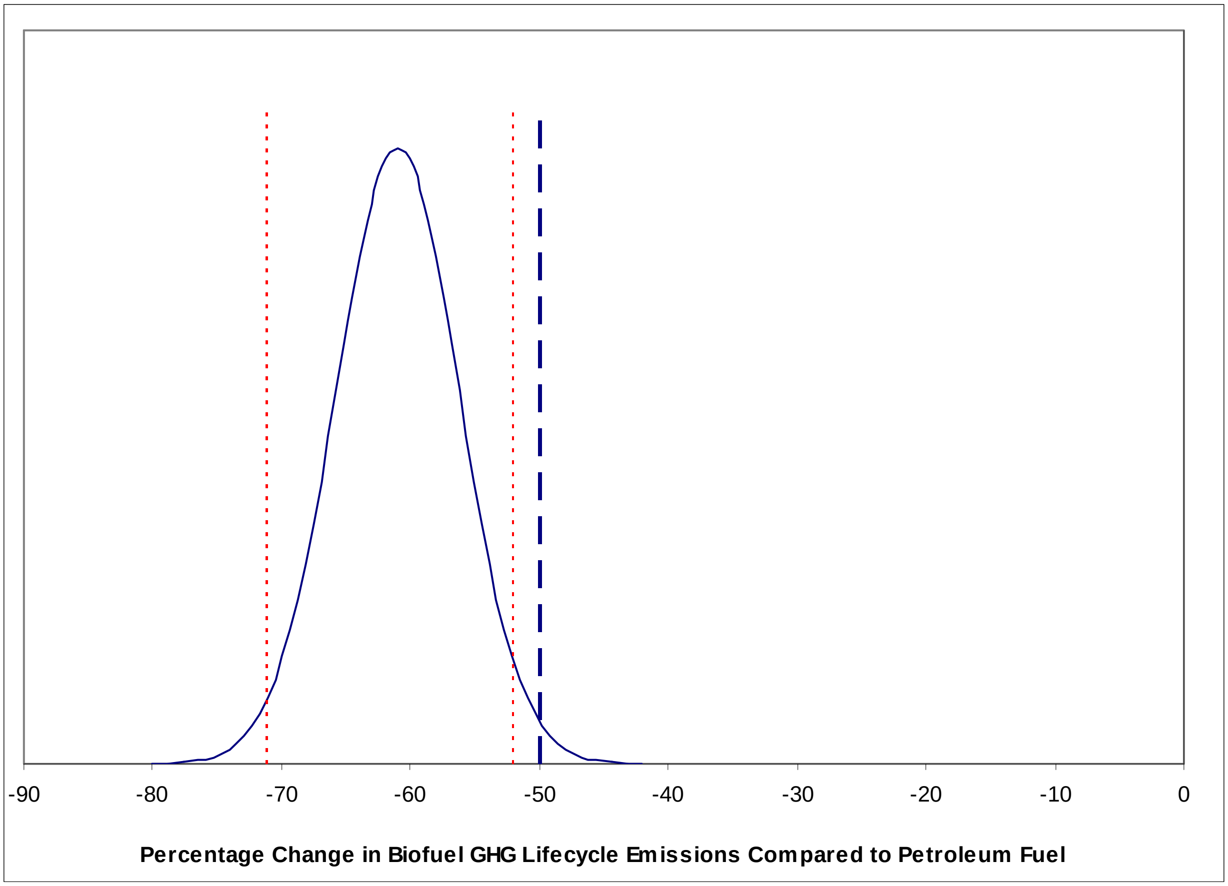


Table V.C-3 below presents results for sugarcane ethanol production and use by lifecycle stage. This table demonstrates the contribution of each stage and their relative significance. The fuel production emissions include displacement of marginal Brazilian electricity because electricity is generated with the sugarcane bagasse co-product. As in similar previous tables, domestic emissions include all emissions sources in the United States, with all other emissions—including emissions from Brazil—presented in the international categories.

Table V.C-3
Lifecycle GHG Emissions for Sugarcane Ethanol, 2022
(kg CO_2e/mmBTU)

Fuel Type	Sugarcane Ethanol	2005 Gasoline Baseline
Net Domestic Agriculture (w/o land use change)	0	0
Net International Agriculture (w/o land use change)	38	0
Domestic Land Use Change	1	0
International Land Use Change, Mean *(Low/High)* 4	*(-5/12)*	0
Fuel Production	-11	19
Fuel and Feedstock Transport	5	0
Tailpipe Emissions	1	79
Total Emissions, Mean *(Low/High)*	38 *(29/46)*	98

Cellulosic Biofuels: In the proposal, we analyzed biochemical cellulosic ethanol pathways from both switchgrass and corn stover, and on that basis proposed that such cellulosic biofuels met the required 60% lifecycle threshold by a considerable margin. As described in Section V.B, we have considerably updated our lifecycle analysis, and have analyzed additional cellulosic biofuel pathways (i.e., thermochemical cellulosic ethanol and a BTL diesel pathway). We analyzed the GHG impacts of each element of the lifecycle for producing and using biofuels from cellulosic biomass, and as for other fuel pathways, considered the range of possible outcomes.

Figure V.C-4 shows the percent change in the average lifecycle GHG emissions in 2022 for ethanol produced from switchgrass using the biochemical process compared to the petroleum gasoline 2005 baseline. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 60% reduction threshold is represented by the dashed line at -60 on the graph. The results for this switchgrass ethanol scenario are that the midpoint of the range of results is a 110% reduction in GHG emissions compared to the gasoline baseline. The 95% confidence interval around that midpoint ranges from 102% reduction to a 117% reduction compared to the gasoline baseline.

Figure V.C-4
Distribution of Results for Switchgrass Biochemical Ethanol
Average 2022 plant: biochemical process producing ethanol, excess electricity production

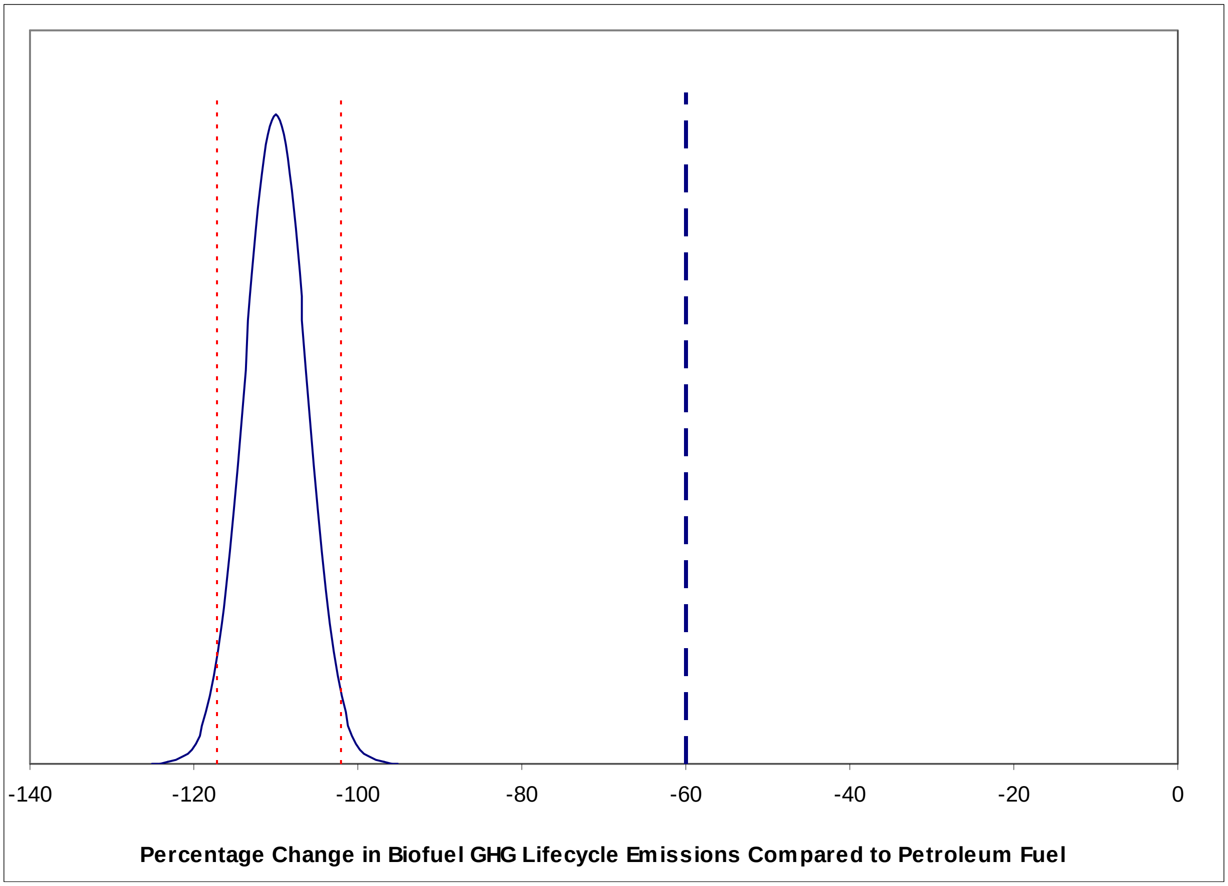


Table V.C-4 below shows lifecycle GHG emissions for cellulosic ethanol produced from switchgrass (as depicted in Figure V.C-4, above) and also corn residue by lifecycle stage, comparing these to the 2005 baseline gasoline. This table is included to demonstrate the contribution of each stage and their relative significance. Results are presented for the biochemical production technology depicted in Figure V.C-4 above and also for thermochemical production technologies. The fuel production emissions for the biochemical pathway include credit for excess electricity generation at the fuel production facility.

Table V.C-4
Lifecycle GHG Emissions for Cellulosic Ethanol, 2022
(kg CO_2e/mmBTU)

Fuel Type	Switchgrass Ethanol		Corn Residue		2005 Gasoline Baseline
Fuel Production Technology	Bio-Chemical	Thermo-Chemical	Bio-Chemical	Thermo-Chemical	
Net Domestic Agriculture (w/o land use change)	6	6	11	11	0
Net International Agriculture (w/o land use change)	0	0	0	0	0
Domestic Land Use Change -2		-3	-11	-11	0
International Land Use Change, Mean *(Low/High)* 15	*(9/23)* 16	*(9/24)* 0		0	0
Fuel Production	-33	4	-33	4	19
Fuel and Feedstock Transport	3 3 2 2 0				
Tailpipe Emissions	1	1	1	1	79
Total Emissions, Mean *(Low/High)*	**-10 *(-17/-2)***	**27 *(20/35)***	**-29**	**7**	**98**

Table V.C-5 below presents lifecycle GHG emissions for cellulosic diesel produced with a Fischer-Tropsch process by lifecycle stage.

Table V.C-5
Lifecycle GHG Emissions for Cellulosic Diesel, 2022
(kg CO_2e/mmBTU)

Fuel Type	Switchgrass Diesel	Corn Residue Diesel	2005 Diesel Baseline
Fuel Production Technology	F-T Diesel	F-T Diesel	
Net Domestic Agriculture	6	11	0

(w/o land use change)			
Net International Agriculture (w/o land use change)	0	0	0
Domestic Land Use Change	-3	-11	0
International Land Use Change, Mean *(Low/High)* 16	*(9/24)*	0 0	
Fuel Production	5	5	18
Fuel and Feedstock Transport	3 2 0		
Tailpipe Emissions	1	1	79
Total Emissions, Mean *(Low/High)*	**29 *(22/37)***	**9**	**97**

Based on the currently available information, we conclude that all modeled cellulosic biofuel pathways are expected to exceed the 60% threshold applicable to cellulosic biofuels.

Assessments of similar feedstock sources: In the proposal, we indicated that although we did not specifically analyze all potential feedstock sources, some feedstock sources are similar enough to those modeled that we believe the modeled results could be extended to these similar feedstock types. Comments received supported this approach and the specific recommendations for similar feedstock designations as proposed.

For this final rule, consistent with what was proposed, we are relying on modeling results and only expanding to additional pathways where we have good information these additional pathways will have lifecycle GHG results which either will not impact our overall assessment of the performance of that fuel pathway or would have at least as good as the modeled pathways. The agricultural sector modeling used for our lifecycle analysis does not predict any soybean biodiesel or corn ethanol will be imported into the U.S., or any imported sugarcane ethanol from production in countries other than Brazil. However, these rules do not prohibit the use in the U.S. of these fuels produced in countries not modeled if they are also expected to comply with the eligibility requirements including meeting the thresholds for GHG performance. Although the GHG emissions of producing these fuels from feedstock grown or biofuel produced in other countries has not been specifically modeled, we do not anticipate their use would impact our conclusions regarding these feedstock pathways. The emissions of producing these fuels in other countries could be slightly higher or lower than what was modeled depending on a number of factors. Our analyses indicate that crop yields for the crops in other countries where these fuels are also most likely to be produced are similar or lower than U.S. values indicating the same or slightly higher GHG impacts. Agricultural sector inputs for the crops in these other countries are roughly the same or lower than the U.S. pointing toward the same or slightly lower GHG impacts. If crop production were to expand due to biofuels in the countries where the models predict these biofuels might additionally be produced, this would tend to lower our assessment of international indirect impacts but could increase our assessment of the domestic (i.e., the country of origin) land use impacts. EPA believes, because of these offsetting factors along with the small amounts of fuel potentially coming from other countries, that incorporating fuels produced in other countries will not impact our threshold analysis. Therefore, fuels of the same fuel type, produced from the same feedstock using the same fuel production technology as modeled fuel pathways will be assessed the same GHG performance decisions regardless of country of origin.

We are also able to conclude that some feedstock types not specifically modeled should be covered as we have good reason to believe their performance would be better than the feedstock pathways modeled. Thus for example, we can conclude that, as in the case of corn stover which we have modeled as a feedstock source, cellulosic biofuel produced from other agricultural waste will also have no land use impact and would be expected to have lifecycle GHG emission impacts similar enough to the modeled corn stover feedstock pathway such that they would also comply. Similarly, we have information on miscanthus indicating that this perennial will yield more feedstock per acre than the modeled switchgrass feedstock without additional GHG inputs such as fertilizer. Therefore we are concluding that since cellulosic biofuel from switchgrass complies with the cellulosic threshold of 60% reduction, fuel produced using miscanthus and other perennial grasses will also surely comply.

We are also determined that biofuel from separated yard and food wastes (which may contain incidental and post-recycled paper and wood wastes) satisfy biofuel thresholds. Separated food waste is largely starch-based and thus qualifies for the advanced biofuel standard of 50% reduction. If the biofuel producer can demonstrate that it is able to quantify the cellulosic portion of food wastes, fuel made from the cellulosic portion can qualify as cellulosic biofuel. Since we have determined that yard wastes are largely cellulosic, biofuel from yard waste will qualify as cellulosic biofuel. The use of separated yard and food wastes for biofuel production including the requirements for demonstrating what portion of food waste is cellulosic feedstock is discussed further in Section II.B.4.d. EPA believes that renewable fuel produced from feedstocks consisting of wastes that would normally be discarded or put to a secondary use, and which have not been intentionally rendered unfit for productive use, should be assumed to have little or no land use emissions of GHGs. The use of wastes that would normally be discarded does not increase the demand for land. For example, the use in biofuel production of food waste from a food processing facility that would normally be placed in a landfill will not increase the demand for land to grow the crops that were purchased by the food processing facility. Similarly, wastes that would not normally be discarded because there are alternative secondary uses for them (for example contaminated vegetable oil might be burned in a boiler) are not produced for the purpose of such secondary use and the use of these feedstocks also does not increase demand for land. Since these waste-derived feedstocks have little or no land use impact, the lifecycle GHG emissions associated with their use for biofuel production are largely the result of the energy required to collect and process the feedstock prior to conversion, and the energy required to convert that feedstock into a biofuel. This has led us to conclude it is reasonable to include a restricted set of additional feedstocks in pathways complying with the applicable threshold.

The look-up table identifies a number of individual fuel "pathways" that allow for the use of waste feedstocks. These feedstocks include 1) waste ethanol from beverage production, 2) waste starches from food production and agricultural residues, 3) waste oils/fats/greases, 4) waste sugar from food and beverage production, and 5) food and beverage production wastes. For the purpose of this rule only, EPA will consider these feedstocks to be “wastes” if they are used as feedstock to produce fuel, but would otherwise normally be discarded or used for another secondary purpose because they are no longer suitable for their original intended use. They may be unsuitable for their original intended use either because they are themselves waste from that original use (e.g., table scraps) or because of contamination, spoilage or other unintentional acts. EPA will not consider any material that has been intentionally rendered unsuitable for its original use to be a "waste."

As discussed in more detail in Section II.B.4.d, EPA has also determined that the biogenic portion of post recycled MSW is eligible to produce renewable fuel and will largely be made up of cellulosic material. Therefore biofuel made from this waste-derived material will qualify as cellulosic biofuel.

EPA has also considered biofuels produced from annual cover crops such as cover crops grown in the winter. These annual cover crops are normally planted as a rotation between primary planted crops or between trees and vines in orchards and vineyards, typically to protect soil from erosion, improve the soil between periods of regular crops, or for other conservation purposes. For annual cover crops grown on the same land as the primary crops, we have determined that there is little or no land use impact such that the GHG emissions associated with them would largely result due to inputs required to grow the crop, harvesting and transporting to the biofuel production facility, turning that feedstock into a biofuel and transporting it to its end use. As such, the biofuel from cellulosic biomass from annual cover crops are, for example, determined to meet requirements of cellulosic biofuel, oil from annual cover crops are determined to meet the requirements of renewable diesel and starches from annual cover crops are determined to meet the requirements of advanced biofuel.

While we have not been able to model all possible feedstocks that can and are being used for renewable fuel production, there are a variety of feedstocks that should have similar enough characteristics to those already modeled to allow them to be grouped in with already modeled fuel pathways. In particular, as discussed below, there are five categories of biofuel feedstock sources for which we are confident, by virtue of their lack of any land-use change impact, in qualifying them for particular renewable fuel standards (D-codes) on the basis of our existing modeling.

1. All crop residues which provide starch or cellulosic feedstock. By virtue of the fact that they do not cause any land-use change impacts, they should all have similar lifecycle GHG impacts. Thus, modeling conducted for corn stover is being extended to other crop residues such as wheat straw, rice straw, and citrus residue. These residues are what remains after a primary crop is harvested, and can be similarly collected, transported and used in biofuel production.
2. Slash, forest thinnings, and forest residue providing cellulosic feedstock. As excess material, these represent another form of residue which should also result in no land-use change GHG impacts. Their GHG emission impacts would only be associated with collection, transport, and processing into biofuel. Consequently, modeling conducted for corn stover is also being extended to these residues.
3. Annual cover crops planted on existing crop land such as winter cover crops and providing cellulosic material, starch or oil for biofuel production. While different from crop residues, these secondary crops also have no land use impact since they are

planted on land otherwise used for primary crop production. GHG emissions would only be associated with growing, harvesting and transporting the secondary crop and then processing into biofuel. In the case of secondary crops that might be used for cellulosic biofuel production, they would also have no land-use change impact, and consequently modeling conducted for corn stover is also being extended to these crops. In the case of secondary crops used for oil production, they would then have no land-use change similar to waste fats, oils and greases. Consequently, modeling conducted for biodiesel and renewable diesel from these waste oils is also being extended to these annual cover crops.

4. Separated food and yard wastes, including food and beverage wastes from food production and processing are another category of waste product that would not have any land-use change impact. These waste products can be used as feedstock for advanced biofuel production or cellulosic biofuel production. Waste oils have already been modeled as complying with the biomass-based diesel standard. Applying our sugarcane results without the land-use change component to waste sugars clearly demonstrates compliance with the advanced biofuel threshold. Applying our corn results without the land-use component to waste starches clearly demonstrates compliance with the renewable fuel standard
5. Perennial grasses including switchgrass and miscanthus. We modeled switchgrass and miscanthus has higher yield per acre without any significant (or perhaps less) inputs such as fertilizer per acre. We believe other perennial grasses likely to compete as feedstock sources will have similar land use and agricultural inputs are therefore confident the results from switchgrass can be extended to miscanthus and other perennial grasses. However, we note that the energy crop industry is just starting to develop and therefore as favored perennial grasses start to emerge, additional analyses may be warranted.

Applicable D-Codes for Fuel Pathways: Based on the above, corn ethanol facilities using natural gas or biomass as the process energy source will meet the applicable 20% GHG performance threshold if it either also uses at least two of the technologies Table V.C-6 or one of the technologies in Table V.C-6 but marketing at least 35% of its DGS as wet. Alternatively, a facility using none of the advanced technologies listed in Table V.C-6 will qualify as producing ethanol meeting the 20% performance threshold if it sells at least 50% of its DGS prior to drying.

Table V.C-6
Modeled Advanced Technologies

Corn oil fractionation
Corn oil extraction
Membrane separation
Raw starch hydrolysis
Combined heat and power

Following the criteria for D-Codes defined in Section II.A-1, the following renewable fuel pathways have been found to comply with the applicable lifecycle GHG thresholds and are therefore eligible for the D-Codes specified in Table V.C-7.

Table V.C-7
D-Code Designations

Fuel Type	Feedstock	Production Process requirements	D-Code
Ethanol	Corn starch	All of the following: Drymill process, using natural gas, biomass or biogas for process energy and at least two advanced technologies from Table V.C-6)	6 (renewable fuel)
Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass or biogas for process energy and one of the advanced technologies from Table V.C-6 plus drying no more than 65% of the DGS it markets annually.	6 (renewable fuel)
Ethanol	Corn starch	All of the following: Dry mill process, using natural gas, biomass or biogas for process energy and drying no more than 50% of the DGS it markets annually.	6 (renewable fuel)
Ethanol	Corn starch	Wet mill process using biomass or biogas for process energy.	6 (renewable fuel)
Ethanol Starches	from agricultural residues; starches from annual cover crops	Fermentation using natural gas, biomass or biogas for process energy	6 (renewable fuel)
Biodiesel, and renewable diesel	Soy bean oil; Oil from annual cover crops Algal oil Biogenic waste	One of the following: Trans-Esterification Hydrotreating Excluding processes that coprocess renewable	4 (biomass-based diesel)

	oils/fats/greases; Non-food grade corn oil	biomass and petroleum	

Biodiesel, and renewable diesel	Soy bean oil; Oil from annual cover crops Algal oil Biogenic waste oils/fats/greases; Non-food grade corn oil	One of the following: Trans-Esterification Hydrotreating Includes only processes that coprocess renewable biomass and petroleum	5 (Advanced)
Ethanol	Sugarcane	Fermentation (Any)	5 (Advanced)
Ethanol	Cellulosic Biomass from agricultural residues, slash, forest thinnings, forest product residues, annual cover crops, switchgrass and miscanthus; cellulosic components of separated yard wastes; cellulosic components of separated food wastes; and cellulosic components of separated MSW	Any 3	(Cellulosic Biofuel)
Cellulosic Diesel, Jet Fuel and Heating Oil	Cellulosic Biomass from agricultural residues, slash, forest thinnings, forest product residues, annual cover crops, switchgrass and miscanthus; cellulosic components of separated yard wastes, cellulosic components of separated food wastes, and cellulosic components of separated MSW	Any 7	(Cellulosic Biofuel or Biomass-Based Diesel)
Butanol	Corn starch	Fermentation; dry mill using natural gas, biomass or biogas for process energy	6 (renewable fuel)
Cellulosic Naphtha	Cellulosic Biomass from agricultural residues, slash, forest thinnings,	Fischer-Tropsch process	3 (Cellulosic Biofuel)

	forest product residues, annual cover crops, switchgrass and miscanthus; cellulosic components of separated yard wastes, cellulosic components of separated food wastes, and cellulosic components of separated MSW		
Ethanol, renewable diesel, jet fuel, heating oil, and naphtha	The non-cellulosic portions of separated food wastes	Any 5	(Advanced)
Biogas	Landfills, sewage and waste treatment plants, manure digesters	Any 5	(Advanced)

Pathways for which we have not made a threshold compliance decision: The pathways identified in the Table V.C-6 represent those pathways we have analyzed and determined meet the applicable thresholds as establish by EISA. We did not analyze all pathways that might be feasible through 2022. In some cases, we did not have sufficient time to complete the necessary lifecycle GHG impact assessment for this final rule. In addition to the pathways identified in Table V.C-6, EPA anticipates modeling grain sorghum ethanol, woody pulp ethanol, and palm oil biodiesel after this final rule and including the determinations in a rulemaking within 6 months. Based on current and projected commercial trends and the status of current analysis at EPA, biofuels from these three pathways are either currently being produced or are planned production in the near-term. Our analyses project that they will be used in meeting the RFS2 volume standard in the near-term. During the course of the NPRM comment period, EPA received detailed information on these pathways and is currently in the process of analyzing these pathways. We have received comments on several additional feedstock/fuel pathways, including rapeseed/canola, camelina, sweet sorghum, wheat, and mustard seed, and we welcome parties to utilize the petition process described below to request EPA to examine additional pathways.

In other cases, we have not modeled the lifecycle GHG performance of pathways because we did not have sufficient information. For those fuel pathways that are different than those pathways EPA has listed in today's regulations, EPA is establishing a petition process whereby a party can petition the Agency to consider new pathways for GHG reduction threshold compliance. The petition process is meant for parties with serious intention to moved forward with production via the petitioned fuel pathway and who have moved sufficiently forward in the business process to show feasibility of the fuel pathway's implementation. The Agency will not consider frivolous petitions with insufficient information and clarity for Agency analysis. In addition, if the petition addresses a fuel pathway that already complies for one or more types of renewable fuels under RFS (e.g., renewable fuel or advanced biofuel), the pathway must have the potential to result in the pathway qualifying for a new renewable fuel category for which it was not previously qualified. Thus, for example, the Agency will not undertake any additional review for a party wishing to get a modified LCA value for a previously approved fuel pathway if the desired new value would not change the overall pathway classification. EPA will process these petitions as expeditiously as possible, taking into consideration that some fuel pathways are closer to the commercial production stage than others. In all events, parties are expected to begin this process with ample lead time as compared to their commercial start dates.

In addition to the technical information described below and listed in today's regulations (see § 80.1416), a petition must include all information required in the registration process except the engineering review. The petition should demonstrate technical and commercial feasibility. For example, a petition could include copies of applications for air or construction permits, copies of blue prints of the facility, or photographs of the facility or pilot plant. The petition must include information necessary to allow EPA to effectively determine the lifecycle green house gas emissions of the fuel. The petitioner must describe the alternative production facility technology applied and supply data establishing the energy savings that will result from the use of the alternative technology. The information required would include, at a minimum, a mass and energy balance for the proposed fuel production process. This would include for example, mass inputs of raw material feedstocks and consumables, mass outputs of fuel product produced as well as co-products and waste materials production. Energy inputs information should include fuels used by type, including purchased electricity. If steam or hot water is purchased, the source and fuel required for its generation would also be reported. Energy output information should include energy content of the fuel product produced (with heating value specified) as well as energy content of any co-products. The petitioner should also report the extent to which excess electricity is generated and distributed outside the production facility. Information on co-products should include the expected use of the co-products and their market value. All information should be provided in a format such that it can be normalized on a fuel output basis (for example, tons feedstock per gallon of fuel produced). Other process descriptions necessary to understand the fuel production process should be included (e.g., process modeling flowcharts). Any other relevant information, including that pertaining to energy saving technologies or other process improvements that document significant differences between the fuel production processes outlined in this rule and that used by the renewable fuel producer, should also be submitted with the petition.

For fuel pathways that utilize feedstocks that have not yet been modeled for this rulemaking, the petition must also submit information on the feedstock. Information would include, at a minimum, the feedstock type and feedstock production source and data on the market value of the feedstock and current uses of the feedstock, if any. The petition should also include chemical input requirements (e.g., fertilizer, pesticides, etc.) and energy use in feedstock production listed by type of energy. Yield information would also be required for both the current yields of the feedstock as well as anticipated changes in feedstock yields over time.

EPA will use the data supplied in the petition and other data and information available to the Agency to technically evaluate whether the information is sufficient for EPA to make a determination of the RFS standards for which the fuel pathway may qualify. If EPA determines that the petition is insufficient for determination, the petitioner will be so notified. If EPA determines it has been provided sufficient data from the petitioner to evaluate the fuel pathway, we will then proceed with any analyses required to make a technical determination of compliance.

EPA anticipates that for some petitioned fuel pathways with unique modifications or enhancements to production technologies of pathways otherwise modeled for the regulations listed today, EPA may be able to evaluate the pathway as a reasonably straight-forward extension of our current assessments. We expect such a determination would be pathway specific, and would be based on a technical analysis that compared the applicant fuel pathway to the fuel a pathway(s) that had already been analyzed. In these cases, EPA would be able make a determination without proceeding through a full rulemaking process. For example, petitions may submit unique biofuel production facility configurations, operations, or co-product pathways that could result in greater efficiencies than the pathways modeled for this rulemaking, but otherwise do not differ greatly from the modeled fuel pathways. In such cases, we would expect to make a decision for that specific pathway without conducting a full rulemaking process. We would expect to evaluate whether the pathway is consistent with the definitions of renewable fuel types in the regulations, generally without going through rulemaking, and issue an approval or disapproval that applies to the petitioner. We anticipate that we will subsequently propose to add the pathway to the regulations.

If EPA determines that a petitioned fuel pathway requires significant new analysis and/or modeling, EPA will need to give notice and seek public comment. For example, we anticipate that pathways with feedstocks or fuel types not yet modeled by EPA will require additional modeling and public comment before a determination of compliance can be made. In these cases, the determination would be incorporated into the annual rulemaking process established in today's regulations.

When EPA makes a technical determination is made that a petitioned fuel pathway qualifies for a RFS volume standard, a D-code will be assigned to the fuel pathway. We anticipate that renewable fuel producers and importers will be able to generate RINs for the additional pathway after the next available update of the EPA Moderated Transaction System (EMTS) that follows a determination. EPA expects to update the EMTS quarterly, as long as necessary. Renewable fuel producers will be able to register the fuel pathway through the EPA Fuels Programs Registration System two weeks after the date of determination, but as described above, will not be able to generate RINs until the quarterly EMTS update.

In the proposal, we suggested a system of temporary D-codes for biofuel pathways we had not analyzed. This was proposed as a means of assuring no undue hardship for biofuel producers using feedstock sources or processing technologies not analyzed by EPA. As proposed, these producers could market their fuel on the basis of temporarily assigned D-codes. While the objective was sound, EPA now believes it is best to properly assure compliance with thresholds on the basis of completed lifecycle GHG assessments. As noted above, the Agency commits to expedited assessment and rulemaking for those pathways most likely to generate biofuel in the immediate future, including ethanol produced from grain sorghum, ethanol, woody pulp ethanol, and palm oil biodiesel. We also plan to continue to model additional pathways we expect will be commercially available in the U.S. as soon as sufficient information is available to complete a quality lifecycle assessment. For these reasons, EPA is not finalizing a provision for assigning temporary D-codes.

D. Total GHG Reductions

Similar to the analysis done in our proposal, our analysis of the overall GHG emission impacts of increased volumes of renewable fuel was performed in parallel with the lifecycle analysis performed to develop the individual fuel thresholds described in previous sections. The same sources of emissions apply such that this analysis includes the effects of three main areas: a) emissions related to the production of biofuels, including the growing of feedstock (corn, soybeans, etc.) with associated domestic and international land use change impacts, transport of feedstock to fuel production plants, fuel production, and distribution of finished fuel; b) emissions related to the extraction, production and distribution of petroleum gasoline and diesel fuel that is replaced by use of biofuels; and c) difference in tailpipe combustion of the renewable and petroleum based fuels.

The main difference between the results of the proposal analysis and the final rule analysis are higher domestic land use change emissions in the final rule analysis. As was the case in the proposal, simply adding up the individual lifecycle results determined in Section V.C. multiplied by their respective volumes would yield a different assessment of the overall impacts. The two analyses are separate in that the overall impacts capture interactions between the different fuels that can not be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions.

While individual fuel analysis generally had small domestic land use change emission impacts, the overall impacts had larger domestic land use change emissions. The primary reason for the difference in domestic land use change between the individual fuel scenarios and the combined fuel scenarios is that when looking at individual fuels there is some interaction between different crops (e.g., corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (e.g., both corn and soybean acres needed) and therefore more land is required.

As discussed in previous sections on lifecycle GHG thresholds there is an initial one time release from land conversion and smaller ongoing releases, but there are also ongoing benefits of using renewable fuels over time replacing petroleum fuel use. Based on the volume scenario considered, the one time land use change impacts result in 313 million metric tons of CO_2-eq. emissions increase. There are, however, based on the biofuel use replacing petroleum fuels, GHG reductions in each year. Totaling the emissions impacts over 30 years but assuming a 0% discount rate over this 30 year period would result in an estimated total NPV reduction in GHG emissions of 4.15 billion tons over 30 years.

This total NPV reduction can be converted into annual average GHG reductions, which can be used for the calculations of the monetized GHG benefits as shown in Section VIII.C.3. This annualized value is based on converting the lump sum present values described above into their annualized equivalents. A comparable value assuming 30 years of GHG emissions changes, but not applying a discount rate to those emissions results in an estimated annualized average emission reduction of approximately 138 million metrics tons of CO_2-eq. emissions.

We also considered the uncertainty in the international land use change emission estimates for the overall impacts. Based on the range of results for the international land use change emissions the overall annualized average emission reductions of increased volumes of renewable fuel could range from -136 to -140 million metrics tons of CO_2-eq. emissions.

E. Effects of GHG Emission Reductions and Changes in Global Temperature and Sea Level

The reductions in CO_2 and other GHGs associated with increased volumes of renewable fuel will affect climate change projections. GHGs mix well in the atmosphere and have long atmospheric lifetimes, so changes in GHG emissions will affect future climate for decades to centuries. Two common indicators of climate change are global mean surface temperature and global mean sea level rise. This section estimates the response in global mean surface temperature and global mean sea level rise projections to the estimated net global GHG emissions reductions associated with increased volumes of renewable fuel.

EPA estimated changes in projected global mean surface temperatures to 2050 using the MiniCAM (Mini Climate Assessment Model) integrated assessment model[182] coupled with the MAGICC (Model for the Assessment of Greenhouse-Gas Induced Climate Change) simple climate model.[183] MiniCAM was used to create the globally and temporally consistent set of climate relevant variables required for running MAGICC. MAGICC was then used to estimate

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[182]MiniCAM is a long-term, global integrated assessment model of energy, economy, agriculture and land use, that considers the sources of emissions of a suite of greenhouse gases (GHGs), emitted in 14 globally disaggregated global regions (i.e., U.S., Western Europe, China), the fate of emissions to the atmosphere, and the consequences of changing concentrations of greenhouse related gases for climate change. MiniCAM begins with a representation of demographic and economic developments in each region and combines these with assumptions about technology development to describe an internally consistent representation of energy, agriculture, land-use, and economic developments that in turn shape global emissions. Brenkert A, S. Smith, S. Kim, and H. Pitcher, 2003: Model Documentation for the MiniCAM. PNNL-14337, Pacific Northwest National Laboratory, Richland, Washington. For a recent report and detailed description and discussion of MiniCAM, see Clarke, L., J. Edmonds, H. Jacoby, H. Pitcher, J. Reilly, R. Richels, 2007. Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations. Sub-report 2.1A of Synthesis and Assessment Product 2.1 by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. Department of Energy, Office of Biological & Environmental Research, Washington, DC., USA, 154 pp.

[183] MAGICC consists of a suite of coupled gas-cycle, climate and ice-melt models integrated into a single framework. The framework allows the user to determine changes in GHG concentrations, global-mean surface air temperature and sea-level resulting from anthropogenic emissions of carbon dioxide (CO_2), methane (CH4), nitrous oxide (N2O), reactive gases (e.g., CO, NO_x, VOCs), the halocarbons (e.g. HCFCs, HFCs, PFCs) and sulfur dioxide (SO2). MAGICC emulates the global-mean temperature responses of more sophisticated coupled Atmosphere/Ocean General Circulation Models (AOGCMs) with high accuracy. Wigley, T.M.L. and Raper, S.C.B. 1992. Implications for Climate and Sea-Level of Revised IPCC Emissions Scenarios Nature 357, 293-300. Raper, S.C.B., Wigley T.M.L. and Warrick R.A. 1996. in Sea-Level Rise and Coastal Subsidence: Causes, Consequences and Strategies J.D. Milliman, B.U. Haq, Eds., Kluwer Academic Publishers, Dordrecht, The Netherlands, pp. 11-45. Wigley, T.M.L. and Raper,
S.C.B. 2002. Reasons for larger warming projections in the IPCC Third Assessment Report J. Climate 15, 2945-2952.

the change in the global mean surface temperature over time. Given the magnitude of the estimated emissions reductions associated with the increased volumes of renewable fuel, a simple climate model such as MAGICC is reasonable for estimating the climate response.

EPA applied the estimated annual GHG emissions changes for the final rule to a MiniCAM baseline emissions scenario.[184] Specifically, the CO_2, N_2O, and CH_4 annual emission changes from 2022-2052 from Section V.D were applied as net reductions to this baseline scenario for each GHG.

Table V.E-1 provides our estimated reductions in projected global mean surface temperatures and mean sea level rise associated with the reductions in GHG emissions due to the increase in renewable fuels in 2022. To capture some of the uncertainty in the climate system, we estimated the changes in projected temperatures and sea level across the most current Intergovernmental Panel on Climate Change (IPCC) range of climate sensitivities, 1.5°C to 6.0°C.[185] To illustrate the time profile of the estimated reductions in projected global mean surface temperatures and mean sea level rise, we have also provided Figures V.E-1 and V.E-2.

Table V.E-1
Estimated Reductions in Projected Global Mean Surface Temperature and Global Mean Sea Level Rise from Baseline in 2020-2050

Climate Sensitivity						
	1.5	2	2.5	3	4.5	6
Year	**Change in global mean surface temperatures (degrees Celsius)**					
2020	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000
2035	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
2040	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
2045	-0.001	-0.001	-0.001	-0.001	-0.002	-0.002
2050	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002
Year	**Change in global mean sea level rise (centimeters)**					
2020	0.000	0.000	0.000	0.000	0.000	0.000

[184] The reference scenario is the MiniCAM reference (no climate policy) scenario used as the basis for the Representative Concentration Pathway RCP4.5 using historical emissions until 2005. This scenario is used because it contains a comprehensive suite of greenhouse and pollutant gas emissions including carbonaceous aerosols. The four RCP scenarios will be used as common inputs into a variety of Earth System Models for inter-model comparisons leading to the IPCC AR5 (Moss et al. 2008). The MiniCAM RCP4.5 is based on the scenarios presented in Clarke et al. (2007) with non-CO_2 and pollutant gas emissions implemented as described in Smith and Wigley (2006). Base-year information has been updated to the latest available data for the RCP process.

[185] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is "likely" to be in the range of 2°C to 4.5°C and described 3°C as a "best estimate." The IPCC goes on to note that climate sensitivity is "very unlikely" to be less than 1.5°C and "values substantially higher than 4.5°C cannot be excluded." IPCC WGI, 2007, *Climate Change 2007 - The Physical Science Basis,* Contribution of Working Group I to the Fourth Assessment Report of the IPCC, http://www.ipcc.ch/.

2025	0.000 0.000 0.000 0.000 0.000 0.000					
2030	-0.001 -0.001 -0.001 -0.001 -0.001 -0.001					
2035	-0.002 -0.002 -0.002 -0.003 -0.003 -0.003					
2040	-0.003 -0.004 -0.004 -0.005 -0.005 -0.006					
2045	-0.005 -0.006 -0.006 -0.007 -0.008 -0.009					
2050	-0.006 -0.008 -0.009 -0.009 -0.011 -0.012					

The results in Table V.E-1 and Figures V.E-1 and V.E-2 show small reductions in the global mean surface temperature and sea level rise projections across all climate sensitivities. Overall, the reductions are small relative to the IPCC's "best estimate" temperature increases by 2100 of 1.8ºC to 4.0ºC.[186] Although IPCC does not issue "best estimate" sea level rise projections, the model-based range across SRES scenarios is 18 to 59 cm by 2099.[187] While the distribution of potential temperatures in any particular year is shifting down, the shift is not uniform. The magnitude of the decrease is larger for higher climate sensitivities. The same pattern appears in the reductions in the sea level rise projections. Thus, we can conclude that the impact of increased volumes of renewable fuel is to lower the risk of climate change, as the probabilities of temperature increase and sea level rise are reduced.

186 IPCC WGI, 2007.

187 "Because understanding of some important effects driving sea level rise is too limited, this report does not assess the likelihood, nor provide a best estimate or an upper bound for sea level rise." IPCC Synthesis Report, p. 45

VI. How Would the Proposal Impact Criteria and Toxic Pollutant Emissions and Their Associated Effects?

This section presents our assessment of the changes in emissions and air quality resulting from the increased renewable fuel volumes needed to meet the RFS2 standards. Increases in emissions of hydrocarbons, nitrogen oxides, particulate matter, and other pollutants are projected to lead to increases in population-weighted annual average ambient PM and ozone concentrations. The air quality impacts, however, are highly variable from region to region. Ambient $PM_{2.5}$ is likely to increase in areas associated with biofuel production and transport and decrease in other areas; for ozone, many areas of the country will experience increases and a few areas will see decreases. Ethanol concentrations will increase substantially; for the other modeled air toxics there are some localized impacts, but relatively little impact on national average concentrations.

A. Overview of Emissions Impacts

Today's action will affect the emissions of "criteria" pollutants (those pollutants for which EPA has established a National Ambient Air Quality Standard has been established), criteria pollutant precursors,[188] and air toxics, which may affect overall air quality and health. Emissions are affected by the processes required to produce and distribute large volumes of biofuels required by today's action and the direct effects of these fuels on vehicle and equipment emissions. As detailed in Chapter 3 of the Regulatory Impact Analysis (RIA), we have estimated emissions impacts of production and distribution-related emissions using the life cycle analysis methodology described in Section V with emission factors for criteria and toxic emissions for each stage of the life cycle, including agriculture, feedstock transportation, and the production and distribution of biofuel; included in this analysis are the impacts of reduced gasoline and diesel refining as these fuels are displaced by biofuels. Emission impacts of tailpipe and evaporative emissions for on and off road sources have been estimated by incorporating "per vehicle" fuel effects from recent research into mobile source emission inventory estimation methods.

In the proposal we analyzed a single renewable fuel volume scenario, largely dependent on ethanol, relative to three different reference cases, including the RFS1 base case. For today's rule we are presenting emission impacts for three fuel volume scenarios relative to two reference cases (RFS1 mandate and AEO) to show a range of the possible effects of biofuels depending on the relative quantities of various biofuels that may be used to meet the overall renewable fuel requirements. We have also updated our modeling for the RFS1 mandate reference case to better reflect the emissions for this case. Table VI.A-1 shows the fuel volumes for the two reference cases and all three control scenarios. Further discussion of these fuel volumes and the subcategories within each are available in Section IV.A. The emission impacts of the primary control scenario (22.2 Bgal of ethanol) are presented here relative to both reference cases. The corresponding results for all three control cases are available in Chapter 3 of the Regulatory Impact Analysis for this rule.

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[188] NOx and VOC are precursors to the criteria pollutant ozone; we group them with criteria pollutants in this chapter for ease of discussion

Table VI.A-1
Renewable Fuel Volumes for Each Reference Case and Control Scenario
(Bgal/year in 2022)

Scenario	Ethanol				Biodiesel	Renewable Diesel	Cellulosic Diesel
	Corn	Cellulosic	Imported	Total			
RFS1 Ref	7.046	0.0	0.0	7.046	0.303	0.0	0.0
AEO Ref	12.29	0.25	0.64	13.18	0.38	0.0	0.0
Low Ethanol	15.0	0.25	2.24	17.49	1.67	0.15	9.26
Mid Ethanol (Primary)	**15.0**	**4.92**	**2.24**	**22.16**	**1.67**	**0.15**	**6.52**
High Ethanol	15.0	16.0	2.24	33.24	1.67	0.15	0.0

There have been a number of other enhancements and corrections to the non-GHG emission inventory estimates since the NPRM, some of which were included in the air quality modeling inventories, while others occurred later than that. The major changes are mentioned here, and all the significant changes are explained in detail in Chapter 3 of the RIA.

One significant change relates to the “downstream” vehicle and equipment emission impacts of using the increased proportions of renewable fuels. In the proposal we provided two different analyses based on two different assumptions regarding the effects of E10 and E85 versus E0 on exhaust emissions from cars and trucks. Those were referred to as "less sensitive" and "more sensitive" cases. Based on analysis of recent emissions test data conducted since publication of the NPRM, we are modeling a single case. As detailed in Section VI.C, the case modeled for the final rule is a hybrid approach, applying “more sensitive” impacts for E10 and pre-Tier 2 light duty vehicles, and applying the “less sensitive” E10 effects for Tier 2 light duty cars and trucks, which means no impact for NOx or non-methane hydrocarbons (NMHC). We have also updated our estimates of evaporative permeation impacts of E10 based on recent studies. Finally, for the final rule inventories we are only claiming emission effects with use of E85 in flex-fueled vehicles relative to E0 for two pollutants: ethanol and acetaldehyde, for which data suggests the effects are more certain. For the “more sensitive case” presented in the NPRM, and used in the air quality modeling, we had estimated changes to additional pollutants (including significant PM reductions) based on some very limited data. Until such time as additional data is collected to enhance this analysis it is premature to use such assumptions.

For “upstream” emissions associated with fuel production and distribution, the largest change that was included in the air quality modeling was the improved estimate of VOC and ethanol vapor emissions during ethanol transport, made possible by a detailed analysis of costs and transport modes conducted by Oak Ridge National Laboratory (ORNL).[189] This change alone more than doubled the predicted overall increase in ethanol emissions from the increased use of renewable fuels, increasing the VOC enough to change the overall VOC impact from a decrease to a substantial increase.

[189] “Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints,” Oak Ridge National Laboratory, U.S. Department of Energy, March 2009.

Significant updates have also been made to emissions from cellulosic biofuel plants, in part to reflect the assumed shift in volumes from cellulosic ethanol to diesel between the proposed and final rules. For cellulosic ethanol plants, after the air quality modeling was done we discovered that the calculation of emissions from these plants had been overestimated due to failing to account for the portion of biomass that is not used for process energy. This change decreases the estimated NOx and CO impacts, and shifts the PM impact of these plants from an increase to a small decrease. However, these changes are counterbalanced by varying degrees by shifting some of the cellulosic volume from ethanol to diesel, which requires nearly twice the biomass as needed by ethanol to produce one gallon. While the net effect of the changes in cellulosic plant emissions is a decrease in NOx and CO emission impacts relative to the proposal, the shift to cellulosic diesel under the primary scenario results in a larger increase in "upstream" PM emissions than reported in the NPRM or used in the air quality analysis.

Updates to agricultural modeling assumptions made between proposal and final had a significant impact on ammonia (NH3) emissions. Final modeling reflects an increase in fertilizer use with the primary control case, which results in a 1.2 percent increase in NH3 emissions, a change from the 0.5 percent decrease projected for the proposal and negligible impact used in the air quality analyses.

Analysis of criteria and toxic emission impacts was performed for calendar year 2022, since this year reflects the full implementation of today's rule. Our 2022 projections account for projected growth in vehicle travel and the effects of applicable emission and fuel economy standards, including Tier 2 and Mobile Source Air Toxics (MSAT) rules for cars and light trucks and recently finalized controls on spark-ignited off-road engines.

The analysis presented here provides estimates of the change in national emission totals that would result from the increased use of renewable fuels to meet the statutory requirements of EISA. These totals may not be a good indication of local or regional air quality and health impacts. These results are aggregated across highly localized sources, such as emissions from ethanol plants and evaporative emissions from cars, and reflect offsets such as decreased emissions from gasoline refineries. The location and composition of emissions from these disparate sources may strongly influence the air quality and health impacts of the increased use of renewable fuels, so full-scale photochemical air quality modeling was also performed to accurately assess this. These localized impacts are discussed in Section VI.D.

Our projected emission impacts for the primary renewable fuel scenario relative to the two reference cases are shown in Table VI.A-2 for 2022. This shows the expected emission changes for the U.S. in that year, and the percent contribution of this impact relative to the total U.S. inventory. Overall we project that increases in the use of renewable fuels will result in significant increases in ethanol and acetaldehyde emissions – increasing the total U.S inventories of these pollutants by 16-18 percent in 2022 relative to the RFS1 mandate case. We project more modest increases in NOx, HC, PM, formaldehyde, 1,3-butadiene, acrolein, and ammonia (NH3) relative to the RFS1 mandate case. We project a 5 percent decrease in CO (due to impacts of ethanol on exhaust emissions from vehicles and nonroad equipment), and a 2.4 percent decrease in benzene (due to displacement of gasoline with ethanol in the fuel pool). Impacts on SO2 and naphthalene are much smaller. Relative to the AEO reference case the results are similar directionally, but smaller in magnitude due to the less drastic differences in fuel volumes.

Table VI.A-2
Total Combined Upstream and Downstream Emission Impacts in 2022 for Primary Scenario Relative to Each Reference Case

Pollutant	RFS1 Mandate		AEO	
	Annual Short Tons	% of Total US Inventory	Annual Short Tons	% of Total US Inventory
NOx 24	7,604	1.95%	184,820	1.45%
HC 10	0,762	0.87%	24,523	0.21%
PM10 69	,013	1.92%	63,323	1.76%
PM2.5 15	,549	0.46%	14,393	0.42%
CO -	2,869,842	-5.30%	-376,419	-0.69%
Benzene -4	,264	-2.41%	-1,004	-0.57%
Ethanol 10	0,123	18.20%	54,137	9.84%
1,3-Butadiene 22	4	1.70%	59	0.45%
Acetaldehyde 5,	848	15.80%	3,108	8.40%
Formaldehyde 35	5	0.48%	130	0.17%
Naphthalene -1		-0.01%	-4	-0.03%
Acrolein 22		0.38%	21	0.35%
SO2 3,	286	0.04%	5,065	0.06%
NH3 48	,711	1.15%	48,711	1.15%

The breakdown of these results by the fuel production /distribution ("well-to-pump" emissions) and vehicle and equipment ("pump-to-wheel") emissions is discussed in the following sections.

B. Fuel Production & Distribution Impacts of the Proposed Program

Fuel production and distribution emission impacts of the increased use of renewable fuels were estimated in conjunction with the development of life cycle GHG emission impacts and the GHG emission inventories discussed in Section V. These emissions are calculated according to the breakdowns of agriculture, feedstock transport, fuel production, and fuel distribution; the basic calculation is a function of fuel volumes in the analysis year and the emission factors associated with each process or subprocess. Additionally, the emission impact of displaced petroleum is estimated, using the same domestic/import shares discussed in Section V above.

In general the basis for this life cycle evaluation was the analysis conducted as part of the Renewable Fuel Standard (RFS1) rulemaking, but enhanced significantly. While our approach for the RFS1 was to rely heavily on the "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation" (GREET) model, developed by the Department of Energy's Argonne National Laboratory (ANL), we are now able to take advantage of additional information and models to significantly strengthen and expand our analysis for this rule. In particular, the modeling of the agriculture sector was greatly expanded beyond the RFS1 analysis, employing economic and agriculture models to consider factors such as land-use impact, agricultural burning, fertilizer, pesticide use, livestock, crop allocation, and crop exports.

Other updates and enhancements to the GREET model assumptions include updated feedstock energy requirements and estimates of excess electricity available for sale from new cellulosic ethanol plants, based on modeling by the National Renewable Energy Laboratory (NREL). Per-gallon emission factors for new corn ethanol plants were updated based on EPA analysis of energy efficiency technologies currently available (such as combined heat and power) and their expected market penetrations. There are no new standards planned at this time that would offer any additional control of emissions from corn or cellulosic ethanol plants. EPA also updated the fuel and feedstock transport emission factors to account for recent EPA emission standards and modeling, such as the locomotive and commercial marine standards finalized in 2008, and revised heavy-duty truck emission rates contained in EPA's draft MOVES2009 model. EPA also modified the ethanol transport distances based on a detailed analysis of costs versus transport mode conducted by Oak Ridge National Laboratory. In addition, GREET does not include air toxics or ethanol. Thus emission factors for ethanol and the following air toxics were added: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein and naphthalene.

Results of these calculations relative to each reference case in 2022 are shown in Table VI.B-1 for the criteria pollutants, ammonia, ethanol and individual air toxic pollutants. Due to the complex interactions involved in projections in the agricultural modeling, we did not attempt to adjust the agricultural inputs of the AEO reference case for the RFS1 mandate reference case. So the fertilizer and pesticide quantities, livestock counts, and total agricultural acres were the same for both reference cases. The agricultural modeling that had been done for the RFS1 rule itself was much simpler and inconsistent with the new modeling, so it would be inappropriate to use those estimates.

The fuel production and distribution impacts of the increased use of renewable fuels on VOC are mainly due to increases in emissions connected with biofuel production, countered by decreases in emissions associated with gasoline production and distribution as ethanol displaces some of the gasoline. Increases in PM2.5, SOx and especially NOx are driven by stationary combustion emissions from the substantial increase in corn and cellulosic ethanol production. Biofuel plants (corn and cellulosic) tend to have greater combustion emissions relative to petroleum refineries on a per-BTU of fuel produced basis. Increases in SOx emissions are also due to increases in agricultural chemical production and transport, while substantial PM increases are also associated with fugitive dust from agricultural operations. Ammonia emissions are expected to increase substantially due to increased ammonia from fertilizer use.

Ethanol vapor and most air toxic emissions associated with fuel production and distribution are projected to increase. Relative to the US total reference case emissions with RFS1 mandate ethanol volumes, increases of 4-13 percent for acetaldehyde and ethanol vapor are especially significant because they are driven directly by the increased ethanol production and distribution. Formaldehyde and acrolein increases are smaller, on the order of 0.4-1 percent. There are also very small decreases in benzene, 1,3-butadiene and naphthalene relative to the US total emissions.

Table VI.B-1
"Upstream" Fuel Production and Distribution Impacts of the Primary Scenario in 2022 Relative to Each Reference Case

Pollutant	RFS1 Mandate		AEO	
	Annual Short Tons	% of Total US Inventory	Annual Short Tons	% of Total US Inventory
NOx 16	9,665	1.34%	164,170	1.29%
HC 77	,014	0.67%	19,737	0.17%
PM10 69	,583	1.94%	63,892	1.78%
PM2.5 15	,864	0.47%	14,707	0.43%
CO 13	5,658	0.25%	130,172	0.24%
Benzene -	231	-0.13%	-236	-0.13%
Ethanol 69	,445	12.63%	35,865	6.52%
1,3-Butadiene -1		-0.01%	0	0.00%
Acetaldehyde 1,	617	4.37%	933	2.52%
Formaldehyde 29	3	0.39%	187	0.25%
Naphthalene -8		-0.06%	-6	-0.04%
Acrolein 67		1.13%	37	0.63%
SO2 3,	266	0.04%	5,044	0.06%
NH3 48	,711	1.15%	48,711	1.15%

C. Vehicle and Equipment Emission Impacts of Fuel Program

The effects of the increased use of renewable fuels on vehicle and equipment emissions are a direct function of the effects of these fuels on exhaust and evaporative emissions from vehicles and off-road equipment, and evaporation of fuel from portable containers. To assess these impacts we conducted separate analyses to quantify the emission impacts of additional E10 due to the increased use of renewable fuels on gasoline vehicles, nonroad spark-ignited engines and portable fuel containers; E85 on cars and light trucks; biodiesel on diesel vehicles; and increased refueling events due to lower energy density of biofuels.[190]

In the proposal we provided two different analyses based on two different assumptions regarding the effects of E10 and E85 on exhaust emissions from cars and trucks. Those were referred to as "less sensitive" and "more sensitive" cases. Based on analysis of recent studies, today's analysis is based on a hybrid of these two scenarios. As detailed in the RIA, EPA and other parties have been gathering additional data on the emission impacts of ethanol fuels on later model vehicles. Data available in time for this analysis supports the hypothesis of the "less sensitive" case that newer technology Tier 2 vehicles are generally able to control for changes to emissions associated with low level ethanol blends; for this analysis we therefore are not

[190] The impact of renewable diesel was not estimated for this analysis; we expect little overall impact on criteria and toxic emissions due to the relatively small volume change, and because emission effects relative to conventional diesel are presumed to be negligible.

attributing any NOx or VOC impact to the use of E10 on these vehicles. The data does show sensitivity for older technology (pre-Tier 2) vehicles, so this analysis does attribute an increase in NOx and decrease in NMHC to the use of E10 in these vehicles. This analysis does not include any emission impacts with use of E85 in flex-fueled vehicles, except for increases in ethanol and acetaldehyde, as the limited data currently available is insufficient to quantify the impact with any degree of certainty. Overall the sensitivity of exhaust emissions to ethanol assumed for the final rule analysis is closer to the "less sensitive" case presented in the proposal; and is generally less sensitive than the case used for the air quality modeling, as discussed in Section VI.D.

We have also updated our estimates of E10 effects on permeation emissions from light-duty vehicles based on testing recently completed by the Coordinating Research Council (CRC), showing that the relative increase in VOC emissions is higher for newer technology vehicles. Nonroad spark ignition (SI) emission impacts of E10 were based on EPA's NONROAD model and show trends similar to light duty vehicles. Biodiesel effects for this analysis were unchanged from the proposal, and are based on an analysis of recent biodiesel testing, detailed in the RIA, showing a 2 percent increase in NOx with a 20 percent biodiesel blend, a 16 percent decrease in PM, and a 14 percent decrease in HC. These results essentially confirm the results of an earlier EPA analysis. This analysis does not attribute any downstream emission impact from the use of renewable diesel or cellulosic-based diesel relative to conventional diesel due to their chemical similarity to diesel fuel and limited test data**.**

Summarized vehicle and equipment emission impacts in 2022, updated as noted above, are shown in Table VI.C-1 relative to each reference case. The totals shown below reflect the net impacts from all mobile sources, including car and truck evaporative emissions, off road emissions, and portable fuel containers. Additional breakdowns by mobile source category can be found in Chapter 3 of the RIA.

Carbon monoxide, PM, benzene, and acrolein are projected to decrease in 2022 as a result of the increased use of renewable fuels, while NOx, HC and the other air toxics, especially ethanol and acetaldehyde, are projected to increase due to the impacts of E10.

Table VI.C-1
"Downstream" Vehicle and Equipment Emission Impacts of the Primary Scenario in 2022 Relative to Each Reference Case

Pollutant	RFS1 Mandate		AEO	
	Annual Short Tons	% of Total US Inventory	Annual Short Tons	% of Total US Inventory
NOx	77,939	0.61%	20,650	0.16%
HC	23,748	0.21%	4,786	0.04%
PM10	-569	-0.02%	-569	-0.02%
PM2.5	-315	-0.01%	-315	-0.01%
CO	-3,005,500	-5.55%	-506,591	-0.94%
Benzene	-4,033	-2.28%	-768	-0.43%
Ethanol	30,678	5.58%	18,272	3.32%
1,3-Butadiene	225	1.71%	59	0.45%
Acetaldehyde	4,231	11.43%	2,175	5.88%
Formaldehyde	62	0.08%	-57	-0.08%
Naphthalene	7	0.05%	2	0.01%
Acrolein	-44	-0.75%	-16	-0.28%
SO2	21	0.00%	21	0.00%
NH3	0	0.00%	0	0.00%

D. Air Quality Impacts

Air quality modeling was performed to assess the projected impact of the renewable fuel volumes required by RFS2 on emissions of criteria and air toxic pollutants. Our air quality modeling reflects the impact of increased renewable fuel use required by RFS2 compared with two different reference cases that include the use of renewable fuels: a 2022 reference case projection based on the RFS1-mandated volume of 7.1 billion gallons of renewable fuels, and a 2022 reference case projection based on the AEO 2007 volume of roughly 13.6 billion gallons of renewable fuels. Thus, the results represent the impact of an incremental increase in ethanol and other renewable fuels. We note that the air quality modeling results presented in this final rule do not constitute the "anti-backsliding" analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action.

It is critical to note that a key limitation of the analysis is that it employed interim emission inventories, which were somewhat enhanced compared to what was described in the proposal, but due to the timing of the analysis did not include some of the later enhancements and corrections of the final emission inventories presented in this FRM (see Section VI.A through VI.C of this preamble). Most significantly, our modeling of the air quality impacts of the renewable fuel volumes required by RFS2 relied upon interim inventories that assumed that ethanol will make up 34 of the 36 billion gallon renewable fuel mandate, that approximately 20 billion gallons of this ethanol will be in the form of E85, and that the use of E85 results in fewer emissions of direct $PM_{2.5}$ from vehicles. The emission impacts and air quality results would be different if, instead of E85, more non-ethanol biofuels are used or mid-level ethanol blends are approved.

In fact, as explained in Section IV, our more recent analyses indicate that ethanol and E85 volumes are likely to be significantly lower than what we assumed in the interim inventories. Furthermore, the final emission inventories do not include vehicle-related PM reductions associated with E85 use, as discussed in Section VI.A and VI.C of this preamble. There are additional, important limitations and uncertainties associated with the interim inventories that must be kept in mind when considering the results:

- Error in $PM_{2.5}$ emissions from locomotive engines
  After the air quality modeling was completed, we discovered an error in the way that $PM_{2.5}$ emissions from locomotive engines were allocated to counties in the inventory. Although there was very little impact on national-level $PM_{2.5}$ emissions, $PM_{2.5}$ emission changes were too high in some counties and too low in others, by varying degrees. As a result, we do not present the modeling results for specific localized $PM_{2.5}$ impacts. However, we have concluded that $PM_{2.5}$ modeling results are still informative for national-level benefits assessment, as discussed at more length in Section VIII.D of this preamble and the RIA.
- Sensitivity of light-duty vehicle exhaust emissions to ethanol blends
  As discussed above in Sections VI.A and VI.C of this preamble, the interim emission inventories used for the air quality modeling analysis are the "more sensitive" case described in the proposal. As a result, the interim inventories used for air quality modeling assume that vehicles operating on E10 have higher NOx emissions and lower VOC, CO and PM exhaust emissions compared to the FRM inventories.
- Cellulosic plant emissions
  The interim emission inventories used in air quality modeling generally assumed higher emissions from cellulosic plants than the FRM inventories, which used revised estimates based on updates to the fraction of biomass burned at these plants. However, as noted in Section VI.A, the shift of some cellulosic volume from ethanol to diesel results in higher PM emissions from cellulosic plants in the final rule inventories than used in the air quality modeling inventories.
- Ethanol volume
  As mentioned above, the interim emission inventories used in our air quality modeling reflect the use of ethanol in about 34 of the mandated 36 billion gallons and do not include any cellulosic diesel. As shown in Table VI.A-1, the FRM inventories assume 22 billion gallons of ethanol in the primary case and 6.5 billion gallons of cellulosic diesel. The inventories used for air quality modeling assume ethanol volumes are more consistent with the FRM's high-ethanol case inventory, which reflects the use of 33 billion gallons of ethanol and no cellulosic diesel.
- Renewable fuel transport emissions
  As discussed in Section 3.3, the estimates of renewable fuel transport volumes and distances differ between the air quality modeling and final rule inventories.

In this section, we present information on current modeled levels of pollution as well as projections for 2022, with respect to ambient $PM_{2.5}$, ozone, selected air toxics, and nitrogen and sulfur deposition. The air quality modeling results indicate that ambient $PM_{2.5}$ is likely to increase in areas associated with biofuel production and transport and decrease in other areas. The results of the air quality modeling also indicate that many areas of the country will experience increases in ambient ozone and a few areas will see decreases in ambient ozone as a result of the renewable fuel volumes required by RFS2. The modeling also shows that ethanol concentrations increase substantially with increases in renewable fuel volumes. For the other modeled air toxics, there are some localized impacts, but relatively little impact on national average concentrations. Our air quality modeling does not show substantial overall nationwide impacts on the annual total sulfur and nitrogen deposition occurring across the U.S. However, the air quality modeling results indicate that the entire Eastern half of the U.S. along with the Pacific Northwest would see increases in nitrogen deposition as a result of increased renewable fuel use. The results of the modeling also show that sulfur deposition will increase in the Midwest and in some rural areas of the west associated with biofuel production. The results are discussed in more detail below and in Section 3.4 of the RIA.

We used the Community Multi-scale Air Quality (CMAQ) photochemical model, version 4.7, for our analysis. This version of CMAQ includes a number of improvements to previous versions of the model that are important in assessing impacts of the increased use of renewable fuels, including additional pathways for formation of soluble organic aerosols (SOA). These improvements are discussed in Section 3.4 of the RIA.

In addition to the limitations of the analysis that result from the use of interim emission inventories rather than the FRM inventories, there are uncertainties in the air quality analysis that should be noted. First, there are uncertainties inherent in the modeling process. Pollutants such as ozone, PM, acetaldehyde, formaldehyde, acrolein, and 1,3-butadiene can be formed secondarily through atmospheric chemical processes. These processes can be very complex, and there are uncertainties in emissions of precursor compounds and reaction pathways. In addition, simplifications of chemistry must be made in order to handle reactions of thousands of chemicals in the atmosphere. Another source of uncertainty involves the hydrocarbon speciation profiles, which are applied to the VOC inventories to break VOC down into individual constituent compounds which react in the atmosphere. Given the complexity of the atmospheric chemistry, the hydrocarbon speciation has an important influence on the air quality modeling results. Speciation profiles for a number of key sources are based on data with significant limitations. Finally, there are uncertainties in the surrogates used to allocate emissions spatially and temporally; this is particularly significant in projecting the location of new ethanol plants, especially future cellulosic biofuel plants. These plants can have large impacts on local emissions. A more detailed discussion of these and additional uncertainties and limitations associated with our air quality modeling is presented in Section 3.4 of the RIA.

1. Particulate Matter

a. Current Levels

$PM_{2.5}$ concentrations exceeding the level of the $PM_{2.5}$ NAAQS occur in many parts of the country. In 2005, EPA designated 39 nonattainment areas for the 1997 $PM_{2.5}$ NAAQS (70 FR 943, January 5, 2005). These areas are composed of 208 full or partial counties with a total population exceeding 88 million. The 1997 $PM_{2.5}$ NAAQS was recently revised and the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 18, 2006. On October 8, 2009, the EPA issued final nonattainment area designations for the 2006 24-hour $PM_{2.5}$ NAAQS (74 FR 58688, November 13, 2009). These designations include 31 areas composed of 120 full or partial counties with a population of over 70 million. In total, there are 54 $PM_{2.5}$ nonattainment areas composed of 245 counties with a population of 101 million people.

b. Projected Levels without RFS2 Volumes

States with $PM_{2.5}$ nonattainment areas are required to take action to bring those areas into compliance in the future. Areas designated as not attaining the 1997 $PM_{2.5}$ NAAQS will need to attain the 1997 standards in the 2010 to 2015 time frame, and then maintain them thereafter. The

2006 24-hour $PM_{2.5}$ nonattainment areas will be required to attain the 2006 24-hour $PM_{2.5}$ NAAQS in the 2014 to 2019 time frame and then be required to maintain the 2006 24-hour $PM_{2.5}$ NAAQS thereafter.

EPA has already adopted many emission control programs that are expected to reduce ambient $PM_{2.5}$ levels and which will assist in reducing the number of areas that fail to achieve the $PM_{2.5}$ NAAQS. Even so, recent air quality modeling for the "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder" rule projects that in 2020, at least 10 counties with a population of almost 25 million may not attain the 1997 annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and 47 counties with a population of over 53 million may not attain the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$.[191] These numbers do not account for those areas that are close to (e.g., within 10 percent of) the $PM_{2.5}$ standards. These areas, although not violating the standards, will also benefit from any reductions in $PM_{2.5}$ ensuring long-term maintenance of the $PM_{2.5}$ NAAQS.

c. Projected Levels with RFS2 Volumes

We are not able to present air quality modeling results which detail changes in $PM_{2.5}$ design values for specific local areas due to the error in the locomotive inventory mentioned in the introduction to this section. However, we do know that ambient $PM_{2.5}$ increases in some areas of the country and decreases in other areas of the country. Ambient $PM_{2.5}$ is likely to increase as a result of emissions at biofuel production plants and from biofuel transport, both of which are more prevalent in the Midwest. PM concentrations are likely to decrease in some areas due to reductions in SOA formation and reduced emissions from gasoline refineries. In addition, decreases in ambient PM are predicted because our modeling inventory assumed that E85 usage reduces PM tailpipe emissions. The decreases in ambient PM from reductions in SOA and tailpipe emissions are likely to occur where there is a higher density of vehicles, such as the Northeast. See Section VIII.D for a discussion of the changes in national average population-weighted $PM_{2.5}$ concentrations.

2. Ozone

a. Current Levels

8-hour ozone concentrations exceeding the level of the ozone NAAQS occur in many parts of the country. In 2008, the U.S. EPA amended the ozone NAAQS (73 FR 16436, March 27, 2008). The final 2008 ozone NAAQS rule set forth revisions to the previous 1997 NAAQS for ozone to provide increased protection of public health and welfare. As of January 6, 2010 there are 51 areas designated as nonattainment for the 1997 8-hour ozone NAAQS, comprising 266 full or partial counties with a total population of over 122 million people. These numbers do not include the people living in areas where there is a future risk of failing to maintain or attain the 1997 8-hour ozone NAAQS. The numbers above likely underestimate the number of counties that are not meeting the ozone NAAQS because the nonattainment areas associated with the more stringent 2008 8-hour ozone NAAQS have not yet been designated.[192] Table VI.D-1

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[191] US EPA (2009). Final Rule "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder". (This rule was signed on December 18, 2009 but has not yet been published in the Federal Register. The signed version of the rule is available at http://epa.gov/otaq/oceanvessels.htm).

[192] EPA recently proposed to reconsider the 2008 NAAQS. Because of the uncertainty the reconsideration proposal creates regarding the continued applicability of the 2008 ozone NAAQS, EPA has used its authority to extend by 1

provides an estimate, based on 2005-07 air quality data, of the counties with design values greater than the 2008 8-hour ozone NAAQS of 0.075 ppm.

Table VI.D-1
Counties with Design Values Greater Than the 2008 Ozone NAAQS Based on 2005-2007 Air Quality Data

NUMBE	R OF COUNTIES	POPULATION[a]
1997 Ozone Standard: counties within the 51 areas currently designated as nonattainment (as of 1/6/10)	266 122,34	3, 799
2008 Ozone Standard: additional counties that would not meet the 2008 NAAQS[b]	227 41,285	,262
Total 493		163,629,061

Notes:
[a] Population numbers are from 2000 census data.
[b] Area designations for the 2008 ozone NAAQS have not yet been made. Nonattainment for the 2008 Ozone NAAQS would be based on three years of air quality data from later years. Also, the county numbers in this row include only the counties with monitors violating the 2008 Ozone NAAQS. The numbers in this table may be an underestimate of the number of counties and populations that will eventually be included in areas with multiple counties designated nonattainment.

b. Projected Levels without RFS2 Volumes

States with 8-hour ozone nonattainment areas are required to take action to bring those areas into compliance in the future. Based on the final rule designating and classifying 8-hour ozone nonattainment areas for the 1997 standard (69 FR 23951, April 30, 2004), most 8-hour ozone nonattainment areas will be required to attain the ozone NAAQS in the 2007 to 2013 time frame and then maintain the NAAQS thereafter. EPA has recently proposed to reconsider the 2008 ozone NAAQS. If EPA promulgates different ozone NAAQS in 2010 as a result of the reconsideration, they would fully replace the 2008 ozone NAAQS and there would no longer be a requirement to designate areas for the 2008 NAAQS. EPA would designate nonattainment areas for a potential new 2010 primary ozone NAAQS based on the reconsideration of the 2008 ozone NAAQS in 2011. The attainment dates for areas designated nonattainment for a potential new 2010 primary ozone NAAQS are likely to be in the 2014 to 2031 timeframe, depending on the severity of the problem.

EPA has already adopted many emission control programs that are expected to reduce ambient ozone levels and assist in reducing the number of areas that fail to achieve the ozone NAAQS. Even so, our air quality modeling projects that in 2022, with all current controls but excluding the impacts of the renewable fuel volumes required by RFS2, up to 7 counties with a population of over 22 million may not attain the 2008 ozone standard of 0.075 ppm (75 ppb). These numbers do not account for those areas that are close to (e.g., within 10 percent of) the 2008 ozone standard. These areas, although not violating the standards, will also benefit from any reductions in ozone ensuring long-term maintenance of the ozone NAAQS.

c. Projected Levels with RFS2 Volumes

year the deadline for promulgating designations for those NAAQS. The new deadline is March 2011. EPA intends to complete the reconsideration by August 31, 2010.

Our modeling indicates that the required renewable fuel volumes will cause increases in ozone design value concentrations in many areas of the country and decreases in ozone design value concentrations in a few areas. Air quality modeling of the expected impacts of the renewable fuel volumes required by RFS2 shows that in 2022, most counties with modeled data, especially those in the southeast U.S., will see increases in their ozone design values. These adverse impacts are likely due to increased upstream emissions of NOx in many areas that are NOx-limited (acting as a precursor to ozone formation). The majority of these design value increases are less than 0.5 ppb. The maximum projected increase in an 8-hour ozone design value is in Morgan County, Alabama, 1.56 ppb and 1.27 ppb when compared with the RFS1 mandate and AEO 2007reference cases respectively. As mentioned above there are some areas which see decreases in their ozone design values. This is likely due to VOC emission reductions at the tailpipe in urban areas that are VOC-limited (reducing VOC's role as a precursor to ozone formation). The maximum decrease projected in an 8-hour ozone design value is in Riverside, CA, 0.66 ppb and 0.6 ppb when compared with the RFS1 mandate and AEO 2007 reference cases respectively. On a population-weighted basis, the average modeled future-year 8-hour ozone design values are projected to increase by 0.28 ppb in 2022 when compared with the RFS1 mandate reference case and increase by 0.16 ppb when compared with the AEO 2007 reference case. On a population-weighted basis the design values for those counties that are projected to be above the 2008 ozone standard in 2022 will see decreases of 0.14 ppb when compared with the RFS1 mandate reference case and 0.15 ppb when compared with the AEO 2007 reference case.

3. Air Toxics

a. Current Levels

The majority of Americans continue to be exposed to ambient concentrations of air toxics at levels which have the potential to cause adverse health effects.[193] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage, as discussed in detail in U.S. EPA's recent Mobile Source Air Toxics Rule.[194] According to the National Air Toxic Assessment (NATA) for 2002,[195] mobile sources were responsible for 47 percent of outdoor toxic emissions, over 50 percent of the cancer risk, and over 80 percent of the noncancer hazard. Benzene is the largest contributor to cancer risk of all 124 pollutants quantitatively assessed in the 2002 NATA and mobile sources were responsible for 59 percent of benzene emissions in 2002. Over the years, EPA has implemented a number of mobile source and fuel controls resulting in VOC reductions, which also reduce benzene and other air toxic emissions.

b. Projected Levels

Our modeling indicates that, while there are some localized impacts, the renewable fuel volumes required by RFS2 have relatively little impact on national average ambient concentrations of the modeled air toxics. An exception is increased ambient concentrations of ethanol. For more information on the air toxics modeling results, see Section 3.4 of the RIA for annual average results and Appendix 3A of the RIA for seasonal average results. Our discussion of the air quality modeling results focuses primarily on impacts of the renewable fuel volumes required by RFS2 in reference to the RFS1 mandate for 2022. Except where specifically

[193] U. S. EPA. (2009) 2002 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2002/
[194] U. S. Environmental Protection Agency (2007). Control of Hazardous Air Pollutants from Mobile Sources; Final Rule. 72 FR 8434, February 26, 2007.
[195] U. S. EPA. (2009) 2002 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2002/

discussed below, air quality modeling results of increased renewable fuel use with RFS2 as compared to the AEO 2007 reference case are presented in Appendix 3A of this RIA.

i. *Acetaldehyde*

Our air quality modeling does not show substantial overall nationwide impacts on ambient concentrations of acetaldehyde as a result of the renewable fuel volumes required by this rule, although there is considerable uncertainty associated with the results. Annual percent changes in ambient concentrations of acetaldehyde are less than 1% for most of the country, and annual absolute changes in ambient concentrations of acetaldehyde are generally less than 0.1 $\mu g/m^3$. Some urban areas show decreases in ambient acetaldehyde concentrations ranging from 1 to 10%, and some rural areas associated with new ethanol plants show increases in ambient acetaldehyde concentrations ranging from 1 to 10% with RFS2 volumes. This increase is due to an increase in emissions of primary acetaldehyde and precursor emissions from ethanol plants. A key reason for the decrease in urban areas is reductions in certain acetaldehyde precursors, primarily alkenes (olefins). Most ambient acetaldehyde is formed from secondary photochemical reactions of numerous precursor compounds, and many photochemical mechanisms are responsible for this process.

The uncertainty associated with these results is described in more detail in Section 3.4 of the RIA. For example, some of the modeled decreases would likely become increases using data recently collected by EPA's Office of Research and Development on the composition of hydrocarbon emissions from gasoline storage, gasoline distribution, and gas cans. Furthermore, as noted in the introduction to Section VI.D, the inventories used for air quality modeling may overestimate NOx, because they assumed that use of E10 would lead to increases in NOx emissions for later model year vehicles. The emission inventories for the final rule no longer make this assumption, based on recent EPA testing results.[196] Because increases in NOx may result in more acetyl peroxy radical forming PAN rather than acetaldehyde, our air quality modeling results may underestimate the ambient concentrations of acetaldehyde.

Some previous U.S. monitoring studies have suggested an insignificant or small impact of increased use of ethanol in fuel on ambient acetaldehyde, as discussed in more detail in Section 3.4 of the RIA. These studies suggest that increases in direct emissions of acetaldehyde are offset by decreases in the secondary formation of acetaldehyde. Other past studies have shown increases in ambient acetaldehyde with increased use of ethanol in fuel, although factors such as differences in vehicle fleet, lack of RVP control, and exclusion of upstream impacts may limit the ability of these studies to inform expected impacts on ambient air quality Given the conflicting results among past studies and the limitations of our analysis, considerable additional work is needed to address the impacts of the renewable fuel volumes required by this rule on ambient concentrations of acetaldehyde.

ii. *Formaldehyde*

[196] "Summary of recent findings for fuel effects of a 10% ethanol blend on light duty exhaust emissions", Memo from Aron Butler to Docket EPA-HQ-OAR-2005-0161

Our air quality modeling results do not show substantial impacts on ambient concentrations of formaldehyde from the renewable fuel volumes required by this rule. Most of the U.S. experiences a 1% or less change in ambient formaldehyde concentrations. Decreases in ambient formaldehyde concentrations range between 1 and 5% in a few urban areas. Increases range between 1 and 2.5% in some rural areas associated with new ethanol plants; this result is due to increases in emissions of primary formaldehyde and formaldehyde precursors from the new ethanol plants. Absolute changes in ambient concentrations of formaldehyde are generally less than 0.1 $\mu g/m^3$.

iii. *Ethanol*

Our modeling projects that the renewable fuel volumes required by this rule will lead to significant nationwide increases in ambient ethanol concentrations. Increases ranging between 10 to 50% are seen across most of the country. The largest increases (more than 100%) occur in urban areas with high amounts of on-road emissions and in rural areas associated with new ethanol plants. Absolute increases in ambient ethanol concentrations are above 1.0 ppb in some urban areas. Analysis of a modeling error that impacted ethanol emissions suggests that this error resulted in overestimates of ethanol impacts by more than 10% across much of the country. For a detailed discussion of this error, please refer to the emissions modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2005-0161).

iv. *Benzene*

Our modeling projects that the renewable fuel volumes required by this rule will lead to small nationwide decreases in ambient benzene concentrations. Decreases in ambient benzene concentrations range between 1 and 10% across most of the country and can be higher in a few urban areas. Absolute changes in ambient concentrations of benzene show reductions up to 0.2 $\mu g/m^3$.

v. *1,3-Butadiene*

The results of our air quality modeling show small increases and decreases in ambient concentrations of 1,3-butadiene in parts of the U.S. as a result of increases in renewable fuel volumes required by RFS2. Generally, decreases occur in some southern areas of the country and increases occur in some northern areas and areas with high altitudes. Percent changes in 1,3-butadiene concentrations are over 50% in several areas; but the changes in absolute concentrations of ambient 1,3-butadiene are generally less than 0.005 $\mu g/m^3$. Annual increases in ambient concentrations of 1,3-butadiene are driven by wintertime changes. These increases appear in rural areas with cold winters and low ambient levels but high contributions of emissions from snowmobiles, and a major reason for this modeled increase may be deficiencies in available emissions test data used to estimate snowmobile 1,3-butadiene emission inventories.

vi. *Acrolein*

Our air quality modeling shows small regional increases and decreases in ambient concentrations of acrolein as a result of increases in renewable fuel volumes required by this rule. Decreases in acrolein concentrations occur in some eastern and southern parts of the U.S. and increases occur in some northern areas and areas associated with new ethanol plants. Changes in absolute ambient concentrations of acrolein are between ± 0.001 µg/m³ with the exception of the increases associated with new ethanol plants. These increases can be up to and above 0.005 µg/m³ with percent changes above 50% and are due to increases in emissions of acrolein from the new plants. Ambient acrolein increases in northern regions are driven by wintertime changes, and occur in the same areas of the country that have wintertime increases in ambient 1,3-butadiene. 1,3-butadiene is a precursor to acrolein, and these increases are likely associated with the same emission inventory issues in areas of high snowmobile usage seen for 1,3-butadiene, as described above.

vii. *Population Metrics*

To assess the impact of projected changes in ambient air toxics as a result of increases in renewable fuel volumes required by this rule, we developed population metrics that show the population experiencing increases and decreases in annual ambient concentrations of the modeled air toxics. Table VI.D-2 below illustrates the percentage of the population impacted by changes of various magnitudes in annual ambient concentrations with the renewable fuel volumes required by RFS2, as compared to the RFS1 mandate reference case.

Table VI.D-2
Percent of Total Population Impacted by Changes in Annual Ambient Concentrations of Toxic Pollutants: RFS2 Compare to RFS1 Mandate

Percent Change in Annual Ambient Concentration	Acetaldehyde	Acrolein	Benzene	1,3-Butadiene	Ethanol	Formaldehyde
≤-100						
>-100 to ≤-50						
>-50 to ≤-10	0.76%		1.18%	1.38%		
>-10 to ≤-5	8.17%	0.18%	12.92%	28.11%		
>-5 to ≤-2.5	13.29%	13.66%	48.76%	31.98%		4.11%
>-2.5 to ≤-1	25.26%	40.13%	23.60%	12.87%		19.30%
> -1 to <1	52.24%	36.03%	13.55%	19.37%		76.08%
≥1 to <2.5	0.24%	3.44%		1.53%		0.48%
≥2.5 to <5	0.04%	2.93%		1.13%	0.22%	0.01%
≥5 to <10	0.02%	2.00%		1.13%	1.23%	
≥10 to <50		1.51%		2.15%	63.29%	
≥50 to <100		0.08%		0.28%	34.49%	
≥100	0.05%		0.06%		0.77%	

Table VI.D-3 shows changes in the population-weighted average ambient concentrations of air toxics that are projected to occur in 2022 with increased renewable fuel use as required by this rule.

Table VI.D-3
Population-Weighted Average Ambient Concentrations of Air Toxics in 2022 with RFS2 Renewable Fuel Requirements

	Population-weighted Concentration (Annual Average in μg/m³) RFS2 v. RFS1 Mandate Reference Case			Population-weighted Concentration (Annual Average in μg/m³) RFS2 v. AEO 2007 Reference Case		
	RFS2	RFS1 Mandate	Diff. RFS2-RFS1	RFS2	AEO 2007	Diff. RFS2-AEO
Acetaldehyde 1.590		1.618	-0.028 1.590		1.613	-0.023
Acrolein 0.017		0.018	-0.001 0.017		0.017	-0.0001
Benzene 0.520		0.535	-0.015	0.520	0.527	-0.007
1,3-Butadiene 0.022		0.023	-0.001 0.022		0.230	-0.208
Ethanol 1.521		1.039	0.482 1.521		1.112	0.409
Formaldehyde 1.549		1.558	-0.009 1.549		0.004	-0.006

4. Nitrogen and Sulfur Deposition

a. Current Levels

Over the past two decades, the EPA has undertaken numerous efforts to reduce nitrogen and sulfur deposition across the U.S. Analyses of long-term monitoring data for the U.S. show that deposition of both nitrogen and sulfur compounds has decreased over the last 17 years although many areas continue to be negatively impacted by deposition. Deposition of inorganic nitrogen and sulfur species routinely measured in the U.S. between 2004 and 2006 were as high as 9.6 kilograms of nitrogen per hectare per year (kg N/ha/yr) and 21.3 kilograms of sulfur per hectare per year (kg S/ha/yr). The data show that reductions were more substantial for sulfur compounds than for nitrogen compounds. These numbers are generated by the U.S. national monitoring network and they likely underestimate nitrogen deposition because neither ammonia nor organic nitrogen is measured. In the eastern U.S., where data are most abundant, total sulfur deposition decreased by about 36% between 1990 and 2005, while total nitrogen deposition decreased by 19% over the same time frame.[197]

b. Projected Levels

Our air quality modeling does not show substantial overall nationwide impacts on the annual total sulfur and nitrogen deposition occurring across the U.S. as a result of increased renewable fuel volumes required by this rule. For sulfur deposition, when compared to the RFS1 mandate reference case, the RFS2 renewable fuel volumes will result in annual percent increases in the Midwest ranging from 1% to more than 4%. Some rural areas in the west, likely associated with new ethanol plants, will also have increases in sulfur deposition ranging from 1% to more than 4% as a result of the RFS2 renewable fuel volumes. When compared to the AEO 2007 reference case, the changes are more limited. The Midwest will still have sulfur deposition increases ranging from 1% to more than 4%, but the size of the area with these changes will be smaller. The Pacific Northwest has minimal areas with increases in sulfur deposition when compared to the AEO 2007 reference case. When compared to both the RFS1 mandate and AEO

[197] U.S. EPA. U.S. EPA's 2008 Report on the Environment (Final Report). U.S. Environmental Protection Agency, Washington, D.C., EPA/600/R-07/045F (NTIS PB2008-112484).

2007 reference cases, areas along the Gulf Coast in Louisiana and Texas will experience decreases in sulfur deposition of 2% to more than 4%. The remainder of the country will see only minimal changes in sulfur deposition, ranging from decreases of less than 1% to increases of less than 1%. For a map of 2022 sulfur deposition impacts and additional information on these impacts, see Section 3.4.2.2 of the RIA.

Overall, nitrogen deposition impacts in 2022 resulting from the renewable fuel volumes required by RFS2 are more widespread than the sulfur deposition impacts. When compared to the RFS1 mandate 2007 reference case, nearly the entire eastern half of the United States will see nitrogen deposition increases ranging from 0.5% to more than 2%. The largest increases will occur in the states of Illinois, Michigan, Indiana, Wisconsin, and Missouri, with large portions of each of these states seeing nitrogen deposition increases of more than 2%. The Pacific Northwest will also experience increases in nitrogen of 0.5% to more than 2%. When compared to the AEO 2007 reference case, the changes in nitrogen deposition are more limited. The eastern half of the United States will still see nitrogen deposition increases ranging from 0.5% to more than 2%; however, the size of the area with these changes will be smaller. Increases of more than 2% will primarily occur only in Illinois, Indiana, Michigan, and Missouri. Fewer areas in the Pacific Northwest will have increases in nitrogen deposition when compared to the AEO 2007 reference case. In both the RFS1 mandate and AEO 2007 reference cases, the Mountain West and Southwest will see only minimal changes in nitrogen deposition, ranging from decreases of less than 0.5% to increases of less than 0.5%. A few areas in Minnesota and western Kansas would experience reductions of nitrogen up to 2%. See Section 3.4.2.2 of the RIA for a map and additional information on nitrogen deposition impacts.

E. Health Effects of Criteria and Air Toxics Pollutants

1. Particulate Matter

a. Background

Particulate matter is a generic term for a broad class of chemically and physically diverse substances. It can be principally characterized as discrete particles that exist in the condensed (liquid or solid) phase spanning several orders of magnitude in size. Since 1987, EPA has delineated that subset of inhalable particles small enough to penetrate to the thoracic region (including the tracheobronchial and alveolar regions) of the respiratory tract (referred to as thoracic particles). Current NAAQS use $PM_{2.5}$ as the indicator for fine particles (with $PM_{2.5}$ referring to particles with a nominal mean aerodynamic diameter less than or equal to 2.5 µm), and use PM_{10} as the indicator for purposes of regulating the coarse fraction of PM_{10} (referred to as thoracic coarse particles or coarse-fraction particles; generally including particles with a nominal mean aerodynamic diameter greater than 2.5 µm and less than or equal to 10 µm, or $PM_{10-2.5}$). Ultrafine particles are a subset of fine particles, generally less than 100 nanometers (0.1 µm) in aerodynamic diameter.

Fine particles are produced primarily by combustion processes and by transformations of gaseous emissions (e.g., SO_X, NO_X and VOC) in the atmosphere. The chemical and physical properties of $PM_{2.5}$ may vary greatly with time, region, meteorology, and source category. Thus,

$PM_{2.5}$ may include a complex mixture of different pollutants including sulfates, nitrates, organic compounds, elemental carbon and metal compounds. These particles can remain in the atmosphere for days to weeks and travel hundreds to thousands of kilometers.

b. Health Effects of PM

Scientific studies show ambient PM is associated with a series of adverse health effects. These health effects are discussed in detail in EPA's 2004 Particulate Matter Air Quality Criteria Document (PM AQCD) and the 2005 PM Staff Paper.[198,199,200] Further discussion of health effects associated with PM can also be found in the RIA for this rule.

Health effects associated with short-term exposures (hours to days) to ambient PM include premature mortality, aggravation of cardiovascular and lung disease (as indicated by increased hospital admissions and emergency department visits), increased respiratory symptoms including cough and difficulty breathing, decrements in lung function, altered heart rate rhythm, and other more subtle changes in blood markers related to cardiovascular health.[201] Long-term exposure to $PM_{2.5}$ and sulfates has also been associated with mortality from cardiopulmonary disease and lung cancer, and effects on the respiratory system such as reduced lung function growth or development of respiratory disease. A new analysis shows an association between long-term $PM_{2.5}$ exposure and a subclinical measure of atherosclerosis.[202,203]

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[198] U.S. EPA (2004). *Air Quality Criteria for Particulate Matter*. Volume I EPA600/P-99/002aF and Volume II EPA600/P-99/002bF. Retrieved on March 19, 2009 from Docket EPA-HQ-OAR-2003-0190 at http://www.regulations.gov/.

[199] U.S. EPA. (2005). *Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper*. EPA-452/R-05-005a. Retrieved March 19, 2009 from http://www.epa.gov/ttn/naaqs/standards/pm/data/pmstaffpaper_20051221.pdf.

[200] The PM NAAQS is currently under review and the EPA is considering all available science on PM health effects, including information which has been published since 2004, in the development of the upcoming PM Integrated Science Assessment Document (ISA). A second draft of the PM ISA was completed in July 2009 and was submitted for review by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board. Comments from the general public have also been requested. For more information, see http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=210586.

[201] U.S. EPA. (2006). *National Ambient Air Quality Standards for Particulate Matte*. 71 FR 61144, October 17, 2006.

[202] Künzli, N., Jerrett, M., Mack, W.J., et al. (2004). Ambient air pollution and atherosclerosis in Los Angeles. *Environ Health Perspect.,113*, 201-206

[203] This study is included in the 2006 Provisional Assessment of Recent Studies on Health Effects of Particulate Matter Exposure. The provisional assessment did not and could not (given a very short timeframe) undergo the extensive critical review by CASAC and the public, as did the PM AQCD. The provisional assessment found that the "new" studies expand the scientific information and provide important insights on the relationship between PM exposure and health effects of PM. The provisional assessment also found that "new" studies generally strengthen the evidence that acute and chronic exposure to fine particles and acute exposure to thoracic coarse particles are associated with health effects. Further, the provisional science assessment found that the results reported in the studies did not dramatically diverge from previous findings, and taken in context with the findings of the AQCD, the new information and findings did not materially change any of the broad scientific conclusions regarding the health effects of PM exposure made in the AQCD. However, it is important to note that this assessment was limited to screening, surveying, and preparing a provisional assessment of these studies. For reasons outlined in Section I.C of the preamble for the final PM NAAQS rulemaking in 2006 (see 71 FR 61148-49, October 17, 2006), EPA based its NAAQS decision on the science presented in the 2004 AQCD.

Studies examining populations exposed over the long term (one or more years) to different levels of air pollution, including the Harvard Six Cities Study and the American Cancer Society Study, show associations between long-term exposure to ambient $PM_{2.5}$ and both all cause and cardiopulmonary premature mortality.[204,205,206] In addition, an extension of the American Cancer Society Study shows an association between $PM_{2.5}$ and sulfate concentrations and lung cancer mortality.[207]

2. Ozone

a. Background

Ground-level ozone pollution is typically formed by the reaction of VOC and NO_X in the lower atmosphere in the presence of heat and sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources, such as highway and nonroad motor vehicles and engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller area sources.

The science of ozone formation, transport, and accumulation is complex.[208] Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions, many of which are sensitive to temperature and sunlight. When ambient temperatures and sunlight levels remain high for several days and the air is relatively stagnant, ozone and its precursors can build up and result in more ozone than typically occurs on a single high-temperature day. Ozone can be transported hundreds of miles downwind from precursor emissions, resulting in elevated ozone levels even in areas with low local VOC or NO_X emissions.

b. Health Effects of Ozone

The health and welfare effects of ozone are well documented and are assessed in EPA's 2006 Air Quality Criteria Document (ozone AQCD) and 2007 Staff Paper.[209, 210] Ozone can

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[204] Dockery, D.W., Pope, C.A. III, Xu, X, et al. (1993). An association between air pollution and mortality in six U.S. cities. *N Engl J Med, 329,* 1753-1759. Retrieved on March 19, 2009 from http://content.nejm.org/cgi/content/full/329/24/1753.

[205] Pope, C.A., III, Thun, M.J., Namboodiri, M.M., Dockery, D.W., Evans, J.S., Speizer, F.E., and Heath, C.W., Jr. (1995). Particulate air pollution as a predictor of mortality in a prospective study of U.S. adults. *Am. J. Respir. Crit. Care Med, 151*, 669-674.

[206] Krewski, D., Burnett, R.T., Goldberg, M.S., et al. (2000). *Reanalysis of the Harvard Six Cities study and the American Cancer Society study of particulate air pollution and mortality.* A special report of the Institute's Particle Epidemiology Reanalysis Project. Cambridge, MA: Health Effects Institute. Retrieved on March 19, 2009 from http://es.epa.gov/ncer/science/pm/hei/Rean-ExecSumm.pdf.

[207] Pope, C. A., III, Burnett, R.T., Thun, M. J., Calle, E.E., Krewski, D., Ito, K., Thurston, G.D., (2002). Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. *J. Am. Med. Assoc., 287*, 1132-1141.

[208] U.S. EPA. (2006). Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). EPA/600/R-05/004aF-cF. Washington, DC: U.S. EPA. Retrieved on March 19, 2009 from Docket EPA-HQ-OAR-2003-0190 at http://www.regulations.gov/.

[209] U.S. EPA. (2006). Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). EPA/600/R-05/004aF-cF. Washington, DC: U.S. EPA. Retrieved on March 19, 2009 from Docket EPA-HQ-OAR-2003-0190 at http://www.regulations.gov/.

irritate the respiratory system, causing coughing, throat irritation, and/or uncomfortable sensation in the chest. Ozone can reduce lung function and make it more difficult to breathe deeply; breathing may also become more rapid and shallow than normal, thereby limiting a person's activity. Ozone can also aggravate asthma, leading to more asthma attacks that require medical attention and/or the use of additional medication. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and highly suggestive evidence that short-term ozone exposure directly or indirectly contributes to non-accidental and cardiopulmonary-related mortality, but additional research is needed to clarify the underlying mechanisms causing these effects. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council (NRC), a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health benefits of reducing ozone exposure.[211] Animal toxicological evidence indicates that with repeated exposure, ozone can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. People who are more susceptible to effects associated with exposure to ozone can include children, the elderly, and individuals with respiratory disease such as asthma. Those with greater exposures to ozone, for instance due to time spent outdoors (e.g., children and outdoor workers), are of particular concern.

The 2006 ozone AQCD also examined relevant new scientific information that has emerged in the past decade, including the impact of ozone exposure on such health effects as changes in lung structure and biochemistry, inflammation of the lungs, exacerbation and causation of asthma, respiratory illness-related school absence, hospital admissions and premature mortality. Animal toxicological studies have suggested potential interactions between ozone and PM with increased responses observed to mixtures of the two pollutants compared to either ozone or PM alone. The respiratory morbidity observed in animal studies along with the evidence from epidemiologic studies supports a causal relationship between acute ambient ozone exposures and increased respiratory-related emergency room visits and hospitalizations in the warm season. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and non-accidental and cardiopulmonary mortality.

3. NO_X and SO_X

a. Background

Nitrogen dioxide (NO_2) is a member of the NO_X family of gases. Most NO_2 is formed in the air through the oxidation of nitric oxide (NO) emitted when fuel is burned at a high temperature. SO_2, a member of the sulfur oxide (SO_X) family of gases, is formed from burning fuels containing sulfur (e.g., coal or oil derived), extracting gasoline from oil, or extracting metals from ore.

[210] U.S. EPA. (2007). Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA-452/R-07-003. Washington, DC, U.S. EPA. Retrieved on March 19, 2009 from Docket EPA-HQ-OAR-2003-0190 at http://www.regulations.gov/.

[211] National Research Council (NRC), 2008. *Estimating Mortality Risk Reduction and Economic Benefits from Controlling Ozone Air Pollution*. The National Academies Press: Washington, D.C.

SO_2 and NO_2 can dissolve in water vapor and further oxidize to form sulfuric and nitric acid which react with ammonia to form sulfates and nitrates, both of which are important components of ambient PM. The health effects of ambient PM are discussed in Section VI.D.1 of this preamble. NO_X along with non-methane hydrocarbon (NMHC) are the two major precursors of ozone. The health effects of ozone are covered in Section VI.D.2.

b. Health Effects of NO_X

Information on the health effects of NO_2 can be found in the U.S. Environmental Protection Agency Integrated Science Assessment (ISA) for Nitrogen Oxides.[212] The U.S. EPA has concluded that the findings of epidemiologic, controlled human exposure, and animal toxicological studies provide evidence that is sufficient to infer a likely causal relationship between respiratory effects and short-term NO_2 exposure. The ISA concludes that the strongest evidence for such a relationship comes from epidemiologic studies of respiratory effects including symptoms, emergency department visits, and hospital admissions. The ISA also draws two broad conclusions regarding airway responsiveness following NO_2 exposure. First, the ISA concludes that NO_2 exposure may enhance the sensitivity to allergen-induced decrements in lung function and increase the allergen-induced airway inflammatory response following 30-minute exposures of asthmatics to NO_2 concentrations as low as 0.26 ppm. In addition, small but significant increases in non-specific airway hyperresponsiveness were reported following 1-hour exposures of asthmatics to 0.1 ppm NO_2. Second, exposure to NO_2 has been found to enhance the inherent responsiveness of the airway to subsequent nonspecific challenges in controlled human exposure studies of asthmatic subjects. Enhanced airway responsiveness could have important clinical implications for asthmatics since transient increases in airway responsiveness following NO_2 exposure have the potential to increase symptoms and worsen asthma control. Together, the epidemiologic and experimental data sets form a plausible, consistent, and coherent description of a relationship between NO_2 exposures and an array of adverse health effects that range from the onset of respiratory symptoms to hospital admission.

Although the weight of evidence supporting a causal relationship is somewhat less certain than that associated with respiratory morbidity, NO_2 has also been linked to other health endpoints. These include all-cause (nonaccidental) mortality, hospital admissions or emergency department visits for cardiovascular disease, and decrements in lung function growth associated with chronic exposure.

c. Health Effects of SO_X

Information on the health effects of SO_2 can be found in the U.S. Environmental Protection Agency Integrated Science Assessment for Sulfur Oxides.[213] SO_2 has long been

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[212] U.S. EPA (2008). *Integrated Science Assessment for Oxides of Nitrogen – Health Criteria (Final Report).* EPA/600/R-08/071. Washington, DC,: U.S.EPA. Retrieved on March 19, 2009 from http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645.

[213] U.S. EPA. (2008). *Integrated Science Assessment (ISA) for Sulfur Oxides – Health Criteria (Final Report).* EPA/600/R-08/047F. Washington, DC: U.S. Environmental Protection Agency. Retrieved on March 18, 2009 from http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=198843

known to cause adverse respiratory health effects, particularly among individuals with asthma. Other potentially sensitive groups include children and the elderly. During periods of elevated ventilation, asthmatics may experience symptomatic bronchoconstriction within minutes of exposure. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the EPA has concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2. Separately, based on an evaluation of the epidemiologic evidence of associations between short-term exposure to SO_2 and mortality, the EPA has concluded that the overall evidence is suggestive of a causal relationship between short-term exposure to SO_2 and mortality.

4. Carbon Monoxide

Carbon monoxide (CO) forms as a result of incomplete fuel combustion. CO enters the bloodstream through the lungs, forming carboxyhemoglobin and reducing the delivery of oxygen to the body's organs and tissues. The health threat from exposures to lower levels of CO is most serious for those who suffer from cardiovascular disease, particularly those with angina or peripheral vascular disease. Epidemiological studies have suggested that exposure to ambient levels of CO is associated with increased risk of hospital admissions for cardiovascular causes, fetal effects, and possibly premature cardiovascular mortality. Healthy individuals also are affected, but only when they are exposed to higher CO levels. Exposure of healthy individuals to elevated CO levels is associated with impairment of visual perception, work capacity, manual dexterity, learning ability and performance of complex tasks. Carbon monoxide also contributes to ozone nonattainment since carbon monoxide reacts photochemically in the atmosphere to form ozone.[214] Additional information on CO related health effects can be found in the Carbon Monoxide Air Quality Criteria Document (CO AQCD).[215,216]

5. Air Toxics

The population experiences an elevated risk of cancer and noncancer health effects from exposure to the class of pollutants known collectively as "air toxics."[217] Fuel combustion contributes to ambient levels of air toxics that can include, but are not limited to, acetaldehyde, acrolein, benzene, 1,3-butadiene, formaldehyde, ethanol, naphthalene and peroxyacetyl nitrate (PAN). Acrolein, benzene, 1,3-butadiene, formaldehyde and naphthalene have significant contributions from mobile sources and were identified as national or regional risk drivers in the 2002 National-scale Air Toxics Assessment (NATA).[218] PAN, which is formed from precursor compounds by atmospheric processes, is not assessed in NATA. Emissions and ambient

[214] U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P-99/001F. This document is available in Docket EPA-HQ-OAR-2004-0008.
[215] U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P-99/001F. This document is available in Docket EPA-HQ-OAR-2004-0008.
[216] The CO NAAQS is currently under review and the EPA is considering all available science on CO health effects, including information which has been published since 2000, in the development of the upcoming CO Integrated Science Assessment Document (ISA). A second draft of the CO ISA was completed in September 2009 and was submitted for review by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board. For more information, see http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=213229.
[217] U. S. EPA. 2002 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2002/risksum.html
[218] U.S. EPA .2009. National-Scale Air Toxics Assessment for 2002. http://www.epa.gov/ttn/atw/nata2002.

concentrations of compounds are discussed in Chapter 3 of the RIA and Section VI.D.3 of this preamble.

a. Acetaldehyd e

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[219] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[220,221] EPA is currently conducting a reassessment of cancer risk from inhalation exposure to acetaldehyde.

The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[222] In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.[223, 224] Data from these studies were used by EPA to develop an inhalation reference concentration. Some asthmatics have been shown to be a sensitive subpopulation to decrements in functional expiratory volume (FEV1 test) and bronchoconstriction upon acetaldehyde inhalation.[225] The agency is currently conducting a reassessment of the health hazards from inhalation exposure to acetaldehyde.

b. Acrolein

Acrolein is extremely acrid and irritating to humans when inhaled, with acute exposure resulting in upper respiratory tract irritation, mucus hypersecretion and congestion. The intense irritancy of this carbonyl has been demonstrated during controlled tests in human subjects, who suffer intolerable eye and nasal mucosal sensory reactions within minutes of exposure.[226] These data and additional studies regarding acute effects of human exposure to acrolein are

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[219] U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

[220] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932.

[221] International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

[222] U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

[223] Appleman, L. M., R. A. Woutersen, V. J. Feron, R. N. Hooftman, and W. R. F. Notten. 1986. Effects of the variable versus fixed exposure levels on the toxicity of acetaldehyde in rats. *J. Appl. Toxicol.* 6: 331-336.

[224] Appleman, L.M., R.A. Woutersen, and V.J. Feron. 1982. Inhalation toxicity of acetaldehyde in rats. I. Acute and subacute studies. *Toxicology.* 23: 293-297.

[225] Myou, S.; Fujimura, M.; Nishi K.; Ohka, T.; and Matsuda, T. 1993. Aerosolized acetaldehyde induces histamine-mediated bronchoconstriction in asthmatics. *Am. Rev. Respir.Dis.*148(4 Pt 1): 940-3.

[226] Sim VM, Pattle RE. Effect of possible smog irritants on human subjects JAMA165: 1980-2010, 1957.

summarized in EPA's 2003 IRIS Human Health Assessment for acrolein.[227] Evidence available from studies in humans indicate that levels as low as 0.09 ppm (0.21 mg/m^3) for five minutes may elicit subjective complaints of eye irritation with increasing concentrations leading to more extensive eye, nose and respiratory symptoms.[228] Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein.[229] Acute exposure effects in animal studies report bronchial hyper-responsiveness.[230] In a recent study, the acute respiratory irritant effects of exposure to 1.1 ppm acrolein were more pronounced in mice with allergic airway disease by comparison to non-diseased mice which also showed decreases in respiratory rate.[231] Based on animal data, individuals with compromised respiratory function (e.g., emphysema, asthma) are expected to be at increased risk of developing adverse responses to strong respiratory irritants such as acrolein.

EPA determined in 2003 that the human carcinogenic potential of acrolein could not be determined because the available data were inadequate. No information was available on the carcinogenic effects of acrolein in humans and the animal data provided inadequate evidence of carcinogenicity.[232] The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.[233]

c. Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of

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[227] U.S. EPA (U.S. Environmental Protection Agency). (2003) Toxicological review of acrolein in support of summary information on Integrated Risk Information System (IRIS) National Center for Environmental Assessment, Washington, DC. EPA/635/R-03/003. Available online at: http://www.epa.gov/ncea/iris.

[228] Weber-Tschopp, A; Fischer, T; Gierer, R; et al. (1977) Experimentelle reizwirkungen von Acrolein auf den Menschen. Int Arch Occup Environ Hlth 40(2):117-130. In German

[229] Integrated Risk Information System File of Acrolein. Office of Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available at http://www.epa.gov/iris/subst/0364.htm

[230] U.S. EPA (U.S. Environmental Protection Agency). (2003) Toxicological review of acrolein in support of summary information on Integrated Risk Information System (IRIS) National Center for Environmental Assessment, Washington, DC. EPA/635/R-03/003. Available online at: http://www.epa.gov/ncea/iris.

[231] Morris JB, Symanowicz PT, Olsen JE, et al. 2003. Immediate sensory nerve-mediated respiratory responses to irritants in healthy and allergic airway-diseased mice. J Appl Physiol 94(4):1563-1571.

[232] U.S. EPA. 2003. Integrated Risk Information System File of Acrolein. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available at http://www.epa.gov/iris/subst/0364.htm

[233] International Agency for Research on Cancer (IARC). 1995. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 63, Dry cleaning, some chlorinated solvents and other industrial chemicals , World Health Organization, Lyon, France.

bone marrow cells in mice.[234,235,236] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[237,238]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[239,240] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[241, 242] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[243,244,245,246] EPA's IRIS program has not yet evaluated these new data.

d. 1,3-Butadiene

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234 U.S. EPA. 2000. Integrated Risk Information System File for Benzene. This material is available electronically at http://www.epa.gov/iris/subst/0276.htm.
235 International Agency for Research on Cancer (IARC). 1982. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France, p. 345-389.
236 Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. 1992. Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.
237 International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.
238 U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.
239 Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.
240 Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.
241 Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.
242 U.S. EPA (2002) Toxicological Review of Benzene (Noncancer Effects). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington DC. This material is available electronically at http://www.epa.gov/iris/subst/0276.htm.
243 Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003) HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.
244 Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002) Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.
245 Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004) Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.
246 Turtletaub, K.W. and Mani, C. (2003) Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.[247,248] The IARC has determined that 1,3-butadiene is a human carcinogen and the U.S. DHHS has characterized 1,3-butadiene as a known human carcinogen.[249,250] There are numerous studies consistently demonstrating that 1,3-butadiene is metabolized into genotoxic metabolites by experimental animals and humans. The specific mechanisms of 1,3-butadiene-induced carcinogenesis are unknown; however, the scientific evidence strongly suggests that the carcinogenic effects are mediated by genotoxic metabolites. Animal data suggest that females may be more sensitive than males for cancer effects associated with 1,3-butadiene exposure; there are insufficient data in humans from which to draw conclusions about sensitive subpopulations. 1,3-butadiene also causes a variety of reproductive and developmental effects in mice; no human data on these effects are available. The most sensitive effect was ovarian atrophy observed in a lifetime bioassay of female mice.[251]

e. Ethanol

EPA is conducting an assessment of the cancer and noncancer effects of exposure to ethanol, a compound which is not currently listed in EPA's IRIS. A description of these effects to the extent that information is available will be presented, as required by Section 1505 of EPAct, in a Report to Congress on public health, air quality and water resource impacts of fuel additives. We expect to release that report in 2010.

Extensive data are available regarding adverse health effects associated with the ingestion of ethanol while data on inhalation exposure effects are sparse. As part of the IRIS assessment, pharmacokinetic models are being evaluated as a means of extrapolating across species (animal to human) and across exposure routes (oral to inhalation) to better characterize the health hazards and dose-response relationships for low levels of ethanol exposure in the environment.

The IARC has classified "alcoholic beverages" as carcinogenic to humans based on sufficient evidence that malignant tumors of the mouth, pharynx, larynx, esophagus, and liver are causally related to the consumption of alcoholic beverages.[252] The U.S. DHHS in the 11th Report on Carcinogens also identified "alcoholic beverages" as a known human carcinogen (they have not evaluated the cancer risks specifically from exposure to ethanol), with evidence for cancer of

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247 U.S. EPA (2002) Health Assessment of 1,3-Butadiene. Office of Research and Development, National Center for Environmental Assessment, Washington Office, Washington, DC. Report No. EPA600-P-98-001F. This document is available electronically at http://www.epa.gov/iris/supdocs/buta-sup.pdf.

248 U.S. EPA (2002) Full IRIS Summary for 1,3-butadiene (CASRN 106-99-0). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington, DC http://www.epa.gov/iris/subst/0139.htm.

249 International Agency for Research on Cancer (IARC) (1999) Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 71, Re-evaluation of some organic chemicals, hydrazine and hydrogen peroxide and Volume 97 (in preparation), World Health Organization, Lyon, France.

250 U.S. Department of Health and Human Services (2005) National Toxicology Program 11th Report on Carcinogens available at: ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932.

251 Bevan, C.; Stadler, J.C.; Elliot, G.S.; et al. (1996) Subchronic toxicity of 4-vinylcyclohexene in rats and mice by inhalation. Fundam. Appl. Toxicol. 32:1-10.

252 International Agency for Research on Cancer (IARC). 1988. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 44, Alcohol Drinking, World Health Organization, Lyon, France.

the mouth, pharynx, larynx, esophagus, liver and breast.[253] There are no studies reporting carcinogenic effects from inhalation of ethanol. EPA is currently evaluating the available human and animal cancer data to identify which cancer type(s) are the most relevant to an assessment of risk to humans from a low-level oral and inhalation exposure to ethanol.

Noncancer health effects data are available from animal studies as well as epidemiologic studies. The epidemiologic data are obtained from studies of alcoholic beverage consumption. Effects include neurological impairment, developmental effects, cardiovascular effects, immune system depression, and effects on the liver, pancreas and reproductive system.[254] There is evidence that children prenatally exposed via mothers' ingestion of alcoholic beverages during pregnancy are at increased risk of hyperactivity and attention deficits, impaired motor coordination, a lack of regulation of social behavior or poor psychosocial functioning, and deficits in cognition, mathematical ability, verbal fluency, and spatial memory.[255,256,257,258,259,260,261,262] In some people, genetic factors influencing the metabolism of ethanol can lead to differences in internal levels of ethanol and may render some subpopulations more susceptible to risks from the effects of ethanol.

f. Form aldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[263] EPA is currently reviewing recently published epidemiological data. For instance, research conducted by the National Cancer Institute (NCI) found an increased risk of nasopharyngeal cancer and lymphohematopoietic malignancies such as leukemia among workers exposed to formaldehyde.[264, 265] In an analysis of the lymphohematopoietic cancer mortality from an

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[253] U.S. Department of Health and Human Services. 2005. National Toxicology Program 11th Report on Carcinogens available at: ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932.

[254] U.S. Department of Health and Human Services. 2000. 10th Special Report to the U.S. Congress on Alcohol and Health. June. 2000.

[255] Goodlett CR, KH Horn, F Zhou. 2005. Alcohol teratogeniesis: mechanisms of damage and strategies for intervention. Exp. Biol. Med. 230:394-406.

[256] Riley EP, CL McGee. 2005. Fetal alcohol spectrum disorders: an overview with emphasis on changes in brain and behavior. Exp. Biol. Med. 230:357-365.

[257] Zhang X, JH Sliwowska, J Weinberg. 2005. Prenatal alcohol exposure and fetal programming: effects on neuroendocrine and immune function. Exp. Biol. Med. 230:376-388.

[258] Riley EP, CL McGee, ER Sowell. 2004. Teratogenic effects of alcohol: a decade of brain imaging. Am. J. Med. Genet. Part C: Semin. Med. Genet. 127:35-41.

[259] Gunzerath L, V Faden, S Zakhari, K Warren. 2004. National Institute on Alcohol Abuse and Alcoholism report on moderate drinking. Alcohol. Clin. Exp. Res. 28:829-847.

[260] World Health Organization (WHO). 2004. Global status report on alcohol 2004. Geneva, Switzerland: Department of Mental Health and Substance Abuse. Available: http://www.who.int/substance_abuse/publications/global_status_report_2004_overview.pdf

[261] Chen W-JA, SE Maier, SE Parnell, FR West. 2003. Alcohol and the developing brain: neuroanatomical studies. Alcohol Res. Health 27:174-180.

[262] Driscoll CD, AP Streissguth, EP Riley. 1990. Prenatal alcohol exposure comparability of effects in humans and animal models. Neurotoxicol. Teratol. 12:231-238.

[263] U.S. EPA (1987) Assessment of Health Risks to Garment Workers and Certain Home Residents from Exposure to Formaldehyde, Office of Pesticides and Toxic Substances, April 1987.

[264] Hauptmann, M.; Lubin, J. H.; Stewart, P. A.; Hayes, R. B.; Blair, A. 2003. Mortality from lymphohematopoetic malignancies among workers in formaldehyde industries. Journal of the National Cancer Institute 95: 1615-1623.

extended follow-up of these workers, NCI confirmed an association between lymphohematopoietic cancer risk and peak exposures.[266] A recent National Institute of Occupational Safety and Health (NIOSH) study of garment workers also found increased risk of death due to leukemia among workers exposed to formaldehyde.[267] Extended follow-up of a cohort of British chemical workers did not find evidence of an increase in nasopharyngeal or lymphohematopoietic cancers, but a continuing statistically significant excess in lung cancers was reported.[268] Recently, the IARC re-classified formaldehyde as a human carcinogen (Group 1).[269]

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation – including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma – particularly in the young.[270,271]

g. Peroxyacetyl nitrate (PAN)

Peroxyacetyl nitrate (PAN) has not been evaluated by EPA's IRIS program. Information regarding the potential carcinogenicity of PAN is limited. As noted in the EPA air quality criteria document for ozone and related photochemical oxidants, cytogenetic studies indicate that PAN is not a potent mutagen, clastogen (a compound that can cause breaks in chromosomes), or DNA-damaging agent in mammalian cells either in vivo or in vitro. Some studies suggest that PAN may be a weak bacterial mutagen at high concentrations much higher than exist in present urban atmospheres.[272]

Effects of ground-level smog causing intense eye irritation have been attributed to

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265 Hauptmann, M.; Lubin, J. H.; Stewart, P. A.; Hayes, R. B.; Blair, A. 2004. Mortality from solid cancers among workers in formaldehyde industries. American Journal of Epidemiology 159: 1117-1130.

266 Beane Freeman, L. E.; Blair, A.; Lubin, J. H.; Stewart, P. A.; Hayes, R. B.; Hoover, R. N.; Hauptmann, M. 2009. Mortality from lymphohematopoietic malignancies among workers in formaldehyde industries: The National Cancer Institute cohort. J. National Cancer Inst. 101: 751-761.

267 Pinkerton, L. E. 2004. Mortality among a cohort of garment workers exposed to formaldehyde: an update. Occup. Environ. Med. 61: 193-200.

268 Coggon, D, EC Harris, J Poole, KT Palmer. 2003. Extended follow-up of a cohort of British chemical workers exposed to formaldehyde. J National Cancer Inst. 95:1608-1615.

269 International Agency for Research on Cancer (IARC). 2006. Formaldehyde, 2-Butoxyethanol and 1-tert-Butoxypropan-2-ol. Volume 88. (in preparation), World Health Organization, Lyon, France.

270 Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. http://www.atsdr.cdc.gov/toxprofiles/tp111.html

271 WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

272 U.S. EPA. 2006. Air quality criteria for ozone and related photochemical oxidants (Ozone CD). Research Triangle Park, NC: National Cetner for Environmental Assesssment; report no. EPA/600/R-05/004aF-cF.3v. page 5-78 Available at http://cfpub.epa.gov/ncea/.

photochemical oxidants, including PAN.[273] Animal toxicological information on the inhalation effects of the non-ozone oxidants has been limited to a few studies on PAN. Acute exposure to levels of PAN can cause changes in lung morphology, behavioral modifications, weight loss, and susceptibility to pulmonary infections. Human exposure studies indicate minor pulmonary function effects at high PAN concentrations, but large inter-individual variability precludes definitive conclusions.[274]

h. Naphthalene

Naphthalene is found in small quantities in gasoline and diesel fuels. Naphthalene emissions have been measured in larger quantities in both gasoline and diesel exhaust compared with evaporative emissions from mobile sources, indicating it is primarily a product of combustion. EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.[275] The draft reassessment completed external peer review.[276] Based on external peer review comments received, additional analyses are being undertaken. This external review draft does not represent official agency opinion and was released solely for the purposes of external peer review and public comment. The National Toxicology Program listed naphthalene as "reasonably anticipated to be a human carcinogen" in 2004 on the basis of bioassays reporting clear evidence of carcinogenicity in rats and some evidence of carcinogenicity in mice.[277] California EPA has released a new risk assessment for naphthalene, and the IARC has reevaluated naphthalene and re-classified it as Group 2B: possibly carcinogenic to humans.[278] Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.[279]

i. Other Air Toxics

[273] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/R-05/004aF-cF, 2006. page 5-63. This document is available in Docket EPA-HQ-OAR-2005-0161. This document may be accessed electronically at: http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html

[274] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/R-05/004aF-cF, 2006. page 5-78. This document is available in Docket EPA-HQ-OAR-2005-0161. This document may be accessed electronically at: http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html

[275] U. S. EPA. 2004. Toxicological Review of Naphthalene (Reassessment of the Inhalation Cancer Risk), Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0436.htm.

[276] Oak Ridge Institute for Science and Education. (2004). External Peer Review for the IRIS Reassessment of the Inhalation Carcinogenicity of Naphthalene. August 2004. http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=84403

[277] National Toxicology Program (NTP). (2004). 11th Report on Carcinogens. Public Health Service, U.S. Department of Health and Human Services, Research Triangle Park, NC. Available from: http://ntp-server.niehs.nih.gov.

[278] International Agency for Research on Cancer (IARC). (2002). Monographs on the Evaluation of the Carcinogenic Risk of Chemicals for Humans. Vol. 82. Lyon, France.

[279] U. S. EPA. 1998. Toxicological Review of Naphthalene, Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0436.htm

In addition to the compounds described above, other compounds in gaseous hydrocarbon and PM emissions from vehicles will be affected by today's final action. Mobile source air toxic compounds that will potentially be impacted include ethylbenzene, polycyclic organic matter, propionaldehyde, toluene, and xylene. Information regarding the health effects of these compounds can be found in EPA's IRIS database.[280]

F. Environmental Effects of Criteria and Air Toxic Pollutants

In this section we discuss some of the environmental effects of PM and its precursors such as visibility impairment, atmospheric deposition, and materials damage and soiling, as well as environmental effects associated with the presence of ozone in the ambient air, such as impacts on plants, including trees, agronomic crops and urban ornamentals, and environmental effects associated with air toxics.

1. Visibility

Visibility can be defined as the degree to which the atmosphere is transparent to visible light.[281] Airborne particles degrade visibility by scattering and absorbing light. Visibility is important because it has direct significance to people's enjoyment of daily activities in all parts of the country. Individuals value good visibility for the well-being it provides them directly, where they live and work, and in places where they enjoy recreational opportunities. Visibility is also highly valued in significant natural areas such as national parks and wilderness areas and special emphasis is given to protecting visibility in these areas. For more information on visibility, see the final 2004 PM AQCD as well as the 2005 PM Staff Paper.[282,283]

EPA is pursuing a two-part strategy to address visibility. First, to address the welfare effects of PM on visibility, EPA has set secondary $PM_{2.5}$ standards which act in conjunction with the establishment of a regional haze program. In setting this secondary standard, EPA has concluded that $PM_{2.5}$ causes adverse effects on visibility in various locations, depending on PM concentrations and factors such as chemical composition and average relative humidity. Second, section 169 of the Clean Air Act provides additional authority to address existing visibility impairment and prevent future visibility impairment in the 156 national parks, forests and wilderness areas categorized as mandatory class I federal areas (62 FR 38680-81, July 18, 1997).[284] In July 1999, the regional haze rule (64 FR 35714) was put in place to protect the

[280] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

[281] National Research Council, 1993. Protecting Visibility in National Parks and Wilderness Areas. National Academy of Sciences Committee on Haze in National Parks and Wilderness Areas. National Academy Press, Washington, DC. This document is available in Docket EPA-HQ-OAR-2005-0161. This book can be viewed on the National Academy Press Website at http://www.nap.edu/books/0309048443/html/

[282] U.S. EPA (2004) Air Quality Criteria for Particulate Matter (Oct 2004), Volume I Document No. EPA600/P-99/002aF and Volume II Document No. EPA600/P-99/002bF. This document is available in Docket EPA-HQ-OAR-2005-0161.

[283] U.S. EPA (2005) Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA-452/R-05-005. This document is available in Docket EPA-HQ-OAR-2005-0161.

[284] These areas are defined in CAA section 162 as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977.

visibility in mandatory class I federal areas. Visibility can be said to be impaired in both $PM_{2.5}$ nonattainment areas and mandatory class I federal areas.

2. At mospheric Deposition

Wet and dry deposition of ambient particulate matter delivers a complex mixture of metals (e.g., mercury, zinc, lead, nickel, aluminum, cadmium), organic compounds (e.g., POM, dioxins, furans) and inorganic compounds (e.g., nitrate, sulfate) to terrestrial and aquatic ecosystems. The chemical form of the compounds deposited depends on a variety of factors including ambient conditions (e.g., temperature, humidity, oxidant levels) and the sources of the material. Chemical and physical transformations of the compounds occur in the atmosphere as well as the media onto which they deposit. These transformations in turn influence the fate, bioavailability and potential toxicity of these compounds. Atmospheric deposition has been identified as a key component of the environmental and human health hazard posed by several pollutants including mercury, dioxin and PCBs.[285]

Adverse impacts on water quality can occur when atmospheric contaminants deposit to the water surface or when material deposited on the land enters a waterbody through runoff. Potential impacts of atmospheric deposition to waterbodies include those related to both nutrient and toxic inputs. Adverse effects to human health and welfare can occur from the addition of excess nitrogen via atmospheric deposition. The nitrogen-nutrient enrichment contributes to toxic algae blooms and zones of depleted oxygen, which can lead to fish kills, frequently in coastal waters. Deposition of heavy metals or other toxins may lead to the human ingestion of contaminated fish, human ingestion of contaminated water, damage to the marine ecology, and limits to recreational uses. Several studies have been conducted in U.S. coastal waters and in the Great Lakes Region in which the role of ambient PM deposition and runoff is investigated.[286,287,288,289,290]

Atmospheric deposition of nitrogen and sulfur contributes to acidification, altering biogeochemistry and affecting animal and plant life in terrestrial and aquatic ecosystems across the U.S. The sensitivity of terrestrial and aquatic ecosystems to acidification from nitrogen and sulfur deposition is predominantly governed by geology. Prolonged exposure to excess nitrogen and sulfur deposition in sensitive areas acidifies lakes, rivers and soils. Increased acidity in surface waters creates inhospitable conditions for biota and affects the abundance and nutritional value of preferred prey species, threatening biodiversity and ecosystem function. Over time, acidifying deposition also removes essential nutrients from forest soils, depleting the capacity of soils to neutralize future acid loadings and negatively affecting forest sustainability. Major

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[285] U.S. EPA (2000) Deposition of Air Pollutants to the Great Waters: Third Report to Congress. Office of Air Quality Planning and Standards. EPA-453/R-00-0005. This document is available in Docket EPA-HQ-OAR-2005-0161.

[286] U.S. EPA (2004) National Coastal Condition Report II. Office of Research and Development/ Office of Water. EPA-620/R-03/002. This document is available in Docket EPA-HQ-OAR-2005-0161.

[287] Gao, Y., E.D. Nelson, M.P. Field, et al. 2002. Characterization of atmospheric trace elements on PM2.5 particulate matter over the New York-New Jersey harbor estuary. *Atmos. Environ.* 36: 1077-1086.

[288] Kim, G., N. Hussain, J.R. Scudlark, and T.M. Church. 2000. Factors influencing the atmospheric depositional fluxes of stable Pb, 210Pb, and 7Be into Chesapeake Bay. *J. Atmos. Chem.* 36: 65-79.

[289] Lu, R., R.P. Turco, K. Stolzenbach, et al. 2003. Dry deposition of airborne trace metals on the Los Angeles Basin and adjacent coastal waters. *J. Geophys. Res.* 108(D2, 4074): AAC 11-1 to 11-24.

[290] Marvin, C.H., M.N. Charlton, E.J. Reiner, et al. 2002. Surficial sediment contamination in Lakes Erie and Ontario: A comparative analysis. *J. Great Lakes Res.* 28(3): 437-450.

effects include a decline in sensitive forest tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*), and a loss of biodiversity of fishes, zooplankton, and macro invertebrates.

In addition to the role nitrogen deposition plays in acidification, nitrogen deposition also causes ecosystem nutrient enrichment leading to eutrophication that alters biogeochemical cycles. Excess nitrogen also leads to the loss of nitrogen sensitive lichen species as they are outcompeted by invasive grasses as well as altering the biodiversity of terrestrial ecosystems, such as grasslands and meadows. For a broader explanation of the topics treated here, refer to the description in Section 3.6.2 of the RIA.

Adverse impacts on soil chemistry and plant life have been observed for areas heavily influenced by atmospheric deposition of nutrients, metals and acid species, resulting in species shifts, loss of biodiversity, forest decline and damage to forest productivity. Potential impacts also include adverse effects to human health through ingestion of contaminated vegetation or livestock (as in the case for dioxin deposition), reduction in crop yield, and limited use of land due to contamination.

Atmospheric deposition of pollutants can reduce the aesthetic appeal of buildings and culturally important articles through soiling, and can contribute directly (or in conjunction with other pollutants) to structural damage by means of corrosion or erosion. Atmospheric deposition may affect materials principally by promoting and accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Particles contribute to these effects because of their electrolytic, hygroscopic, and acidic properties, and their ability to adsorb corrosive gases (principally sulfur dioxide). The rate of metal corrosion depends on a number of factors, including: the deposition rate and nature of the pollutant; the influence of the metal protective corrosion film; the amount of moisture present; variability in the electrochemical reactions; the presence and concentration of other surface electrolytes; and the orientation of the metal surface.

3. Plant and Ecosystem Effects of Ozone

Elevated ozone levels contribute to environmental effects, with impacts to plants and ecosystems being of most concern. Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even low concentrations experienced for a longer duration have the potential to create chronic stress on vegetation. Ozone damage to plants includes visible injury to leaves and impaired photosynthesis, both of which can lead to reduced plant growth and reproduction, resulting in reduced crop yields, forestry production, and use of sensitive ornamentals in landscaping. In addition, the impairment of photosynthesis, the process by which the plant makes carbohydrates (its source of energy and food), can lead to a subsequent reduction in root growth and carbohydrate storage below ground, resulting in other, more subtle plant and ecosystems impacts.

These latter impacts include increased susceptibility of plants to insect attack, disease, harsh weather, interspecies competition and overall decreased plant vigor. The adverse effects of ozone on forest and other natural vegetation can potentially lead to species shifts and loss from the affected ecosystems, resulting in a loss or reduction in associated ecosystem goods and services. Lastly, visible ozone injury to leaves can result in a loss of aesthetic value in areas of special scenic significance like national parks and wilderness areas. The final 2006 Ozone Air Quality Criteria Document presents more detailed information on ozone effects on vegetation and ecosystems.

4. Environmental Effects of Air Toxics

Fuel combustion emissions contribute to ambient levels of pollutants that contribute to adverse effects on vegetation. PAN is a well-established phytotoxicant causing visible injury to leaves that can appear as metallic glazing on the lower surface of leaves with some leafy vegetables exhibiting particular sensitivity (e.g., spinach, lettuce, chard).[291, 292, 293] PAN has been demonstrated to inhibit photosynthetic and non-photosynthetic processes in plants and retard the growth of young navel orange trees.[294, 295] In addition to its oxidizing capability, PAN contributes nitrogen to forests and other vegetation via uptake as well as dry and wet deposition to surfaces. As noted in Section IX, nitrogen deposition can lead to saturation of terrestrial ecosystems and research is needed to understand the impacts of excess nitrogen deposition experienced in some areas of the country on water quality and ecosystems.[296]

Volatile organic compounds (VOCs), some of which are considered air toxics, have long been suspected to play a role in vegetation damage.[297] In laboratory experiments, a wide range of tolerance to VOCs has been observed.[298] Decreases in harvested seed pod weight have been reported for the more sensitive plants, and some studies have reported effects on seed germination, flowering and fruit ripening. Effects of individual VOCs or their role in conjunction with other stressors (e.g., acidification, drought, temperature extremes) have not been well studied. In a recent study of a mixture of VOCs including ethanol and toluene on herbaceous plants, significant effects on seed production, leaf water content and photosynthetic efficiency were reported for some plant species.[299]

Research suggests an adverse impact of vehicle exhaust on plants, which has in some

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[291] Nouchi I, S Toyama. 1998. Effects of ozone and peroxyacetyl nitrate on polar lipids and fatty acids in leaves of morning glory and kidney bean. Plant Physiol. 87:638-646.
[292] Oka E, Y Tagami, T Oohashi, N Kondo. 2004. A physiological and morphological study on the injury caused by exposure to the air pollutant, peroxyacetyl nitrate (PAN), based on the quantitative assessment of the injury. J Plant Res. 117:27-36.
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[297] US EPA. 1991. Effects of organic chemicals in the atmosphere on terrestrial plants. EPA/600/3-91/001.
[298] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341-343.
[299] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341-343.

cases been attributed to aromatic compounds and in other cases to nitrogen oxides.[300, 301, 302] The impacts of VOCs on plant reproduction may have long-term implications for biodiversity and survival of native species near major roadways. Most of the studies of the impacts of VOCs on vegetation have focused on short-term exposure and few studies have focused on long-term effects of VOCs on vegetation and the potential for metabolites of these compounds to affect herbivores or insects.

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VII. Impacts on Cost of Renewable Fuels, Gasoline, and Diesel

We have assessed the impacts of the renewable fuel volumes required by EISA on their costs and on the costs of the gasoline and diesel fuels into which the renewable fuels will be blended. More details of feedstock costs are addressed in Section VIII.A.

A. Renewable Fuel Production Costs

1. Ethanol Production Costs

a. Corn Ethanol

A significant amount of work has been done in the last decade surveying and modeling the costs involved in producing ethanol from corn in order to serve business and investment purposes as well as to try to educate energy policy decisions. Corn ethanol costs for our work were estimated using models developed and maintained by USDA. Their work has been described in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process, and compares well with cost information found in surveys of existing plants. [303,304] The USDA models were adjusted to reflect the energy usage we anticipate for the average ethanol plant in 2022 and intermediate years, as well as the prices of energy and agricultural commodities as projected by AEO and the FASOM model respectively.

For our policy case scenario, we used corn prices of $3.60/bu in 2022 with corresponding DDGS prices of $124.74/ton (all 2007$). These estimates are taken from agricultural economics modeling work done for this rule using the Forestry and Agricultural Sector Optimization Model (see Section VIII.A).

For natural gas-fired ethanol production producing dried co-product (currently describes the largest fraction of the industry), in the policy case corn feedstock minus DDGS sale credit represents about 54% of the final per-gallon cost, while utilities, facility, chemical and enzymes, and labor comprise about 22%, 13%, 7%, and 4%, respectively. Thus, the cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS, and relatively insensitive to economy of scale over the range of plant sizes typically seen (40-100 MMgal/yr).

We expect that several process fuels will be used to produce corn ethanol (see RIA Section 1.4), which are presented by their projected 2022 volume production share in Table VII.A.1-1 and cost impacts for each in Table VII.A.1-2.[305]

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[303] Kwaitkowski, J.R., Macon, A., Taylor, F., Johnston, D.B.; *Industrial Crops and Products* 23 (2006) 288-296
[304] Shapouri, H., Gallagher, P.; USDA's 2002 Ethanol Cost-of-Production Survey (published July 2005)
[305] Projected fuel mix was taken from Mueller, S., Energy Research Center at the University of Chicago; An Analysis of the Projected Energy Use of Future Dry Mill Corn Ethanol Plants (2010-2030); cost estimates were derived from modifications to the USDA process models.

Table VII.A.1-1
Projected 2022 Breakdown of Fuel Types Used to Estimate Production Cost of Corn Ethanol, Percent Share of Total Production Volume

	Fuel Type				Total by Plant Type
Plant Type	Biomass	Coal	Natural Gas	Biogas	All Fuels
Coal/Biomass Boiler	11%	0%	-	-	11%
Coal/Biomass Boiler + CHP	10%	4%	-	-	14%
Natural Gas Boiler	-	-	49%	14%	63%
Natural Gas Boiler + CHP	- -		12%	-	12%
Total by Fuel Type	21%	4%	61%	14%	100%

Table VII.A.1-2
Projected 2022 Breakdown of Cost Impacts By Fuel Type Used in Estimating Production Cost of Corn Ethanol, Dollars Per Gallon Relative to Natural Gas Baseline

	Fuel Type				Total by Plant Type
Plant Type	Biomass [a]	Coal	Natural Gas	Biogas [b]	All Fuels
Coal/Biomass Boiler	+\$0.009	+\$0.009	-	-	-
Coal/Biomass Boiler + CHP	-\$0.021	-\$0.021	-	-	-
Natural Gas Boiler	-	-	baseline	+\$0.00	-
Natural Gas Boiler + CHP	- -		-\$0.032	-	-
Total by Fuel Type	-	-	-	-	-\$0.006

[a] Assumes biomass has same plant-delivered cost as coal.
[b] Assumes biogas has same plant-delivered cost as natural gas.

In addition to the primary fuel type used by ethanol production facilities, we also anticipate new technologies and efficiency improvements will impact the cost of ethanol production. More efficient motors and turbines are currently under development and are likely to be adopted by ethanol producers as ways to lower green house gas emissions and reduce energy costs. Several new process technologies, including corn oil extraction, corn fractionation, cold starch fermentation, and ethanol dehydration membranes will allow ethanol producers to further reduce energy consumption and produce higher value co-products. These technologies are discussed in sections 1.4.1.3 and 1.5.1.3 of the RIA. In order to reflect the cost advantages of ethanol producers using these technologies the USDA models were adapted to take into account the capital costs, lower energy usage, and higher value co-products that result from the adoption of these new technologies. The projected adoption rates of these technologies, and their impacts on the production cost of corn ethanol, are summarized in Table VII.A.1-3 below. More detail on how the USDA models were adjusted and the impact this had on the average price of ethanol production can be found in section 4.1.1.1 of the RIA.

Table VII.A.1-3
Projected Cost Impacts or New Corn Ethanol Technologies

Technology	Percent of Plants Adopting Technology	Cost Impact (Change from Baseline)	Weighted Cost Impact
More Efficient Boilers/Motors/Turbines	100% Baseline		$0.00/gal
Raw Starch Hydrolysis	22%	-$0.066/gal	-$0.015/gal
Corn Fractionation	20%	-$0.093/gal	-$0.019/gal
Corn Oil Extraction	70%	-$0.079/gal	-$0.055/gal
Membrane Separation	5%	-$0.064/gal	-$0.003/gal
Total Cost Impact	N/A	N/A	-$0.092/gal

Whether or not the distillers grains and solubles (DGS) are dried also has an impact on the cost of ethanol production. Drying the DGS is an energy intensive process and results in a significant increase energy usages as well as cost. The advantages of dry DGS are reduced transportation costs and a product that is less susceptible to spoilage, and can therefore be sold to a much wider market. If the DGS can be sold wet, the cost of ethanol production can be reduced by $0.083 per gallon. A 2007 survey of ethanol producers indicated that 37% of DGS were being sold wet. We anticipate that this percentage of wet DGS will remain constant in 2022. The net cost impact of selling 37% of the DGS wet is an average cost reduction of $0.031 per gallon.

Table VII.A.1-4
Average Ethanol Cost of Production

Baseline Cost of Production (Natural Gas, no new technologies, 100% dry DGS)	$1.627/gal
Fuel Type Cost Impact	-$0.006/gal
New Technology Cost Impact	-$0.092/gal
DGS Drying Cost Impact	-$0.031/gal
Average Cost of Ethanol Production (2022)	$1.499/gal

Based on energy prices from EIA's Annual Energy Outlook (AEO) April 2009 updated reference case ($116/bbl crude oil), we arrive at a production cost of $1.50/gal. More details on the ethanol production cost estimates can be found in Chapter 4 of the RIA. This estimate represents the full cost to the plant operator, including purchase of feedstocks, energy required for operations, capital depreciation, labor, overhead, and denaturant, minus revenue from sale of co-products. The capital cost for a 65 MMgal/yr natural gas fired dry mill plant is estimated at $97MM (the projected average size of such plants in 2022).

Similarly, coal and biomass fired plants were assumed to be 110 MGY in capacity, with an estimated capital cost of $184MM. [306] Despite the lower operating costs of coal and biomass fired plants the higher capital costs result, on average, ethanol produced in a facility using coal or biomass as a primary energy source results in a per-gallon cost $0.01/gal higher compared to production using natural gas. See Chapter 4.1 of the RIA for more details.

In this cost estimation work, we did not assume any pelletizing of DDGS. Pelletizing is expected to improve ease of shipment to more distant markets, which may become more important at the larger volumes projected for the future. However, while many in industry are aware of this technology, those we spoke with are not employing it in their plants, and do not expect widespread use in the foreseeable future. According to USDA's model, pelletizing adds $0.035/gal to the ethanol production cost.

Note that the ethanol production cost given here does not account for any subsidies on production or sale of ethanol, and is independent of the market price of ethanol.

b. Cellulosic Ethanol

i. *Feedstock Costs*

Cellulosic Feedstock Costs

To estimate the cost of producing cellulosic biofuels, it was first necessary to estimate the cost of harvesting, storing, processing and transporting the feedstocks to the biofuel production facilities. Ethanol or other cellulosic biofuels can be produced from crop residues such as corn stover, wheat, rice, oat, and barley straw, sugar cane bagasse, and sorghum, from other cellulosic plant matter such as forest thinnings and forest-fuel removal, pulping residues, and from the cellulosic portions of municipal solid waste (MSW).

Our feedstock supply analysis projected that energy crops would be the most abundant of the cellulosic feedstocks, comprising about 49% of the total biomass feedstock inventory. Agricultural residues, predominantly corn stover, make up approximately 36% of the total, followed by MSW at approximately 15% and forestry residue at about 1%. At present, there are no commercial sized cellulosic ethanol plants in the U.S. Likewise, there are no commercially proven, fully-integrated feedstock supply systems dedicated to providing any of the feedstocks we mentioned to ethanol facilities of any size, although certain biomass is harvested for other purposes. For this reason, our feedstock cost estimates are projections and not based on any existing market data.

Our feedstock costs include an additional preprocessing cost that many other feedstock cost estimates do not include – thus our costs may seem higher. We used biofuel plant cost estimates provided by NREL which no longer includes the cost for finely grinding the feedstock prior to feeding it to the biofuel plant. Thus, our feedstock costs include an $11 per dry ton cost to account for the costs of this grinding operation, regardless of whether this operation occurs in the field or at the plant gate.

[306] Capital costs for a natural gas fired plant were taken from USDA cost model; incremental costs to use coal as the primary energy source were derived from conversations with ethanol plant construction contractors.

Crop Residue and Energy Crops

Crop residue harvest is currently a secondary harvest; that is they are harvested or gathered only after the prime crop has been harvested. In most northern areas, the harvest periods will be short due to the onset of winter weather. In some cases, it may be necessary to gather a full year's worth of residue within just a few weeks. Consequently, to accomplish this hundreds of pieces of farm equipment will be required for a few weeks each year to complete a harvest. Winter conditions in the South make it somewhat easier to extend the harvest periods; in some cases, it may be possible to harvest a residue on an as needed basis.

During the corn grain harvest, generally only the cob and the leaves above the cob are taken into the harvester. Thus, the stover harvest would likely require some portion of the standing-stalks be mowed or shredded, following which the entire residue, including that discharged from the combine residue-spreader, would need to be raked. Balers, likely a mix of large round and large square balers, would follow the rakes. The bales would then be removed from the field, usually to the field-side in the first operation of the actual harvest, following which they would then be hauled to a satellite facility for intermediate storage. For our analysis we assumed that bales would then be hauled by truck and trailer to the processing plant on an as needed basis.

The small grain straws (wheat, rice, oats, barley, sorghum) are cut near the ground at the time of grain harvest and thus likely won't require further mowing or shredding. They will likely need to be raked into a windrow prior to baling. Because small grain straws have been baled and stored for many years, we don't expect unusual requirements for handling these residues. Their harvest and storage costs will likely be less than those for corn stover, but their overall quantity is much less than corn stover (corn stover makes up about 68% of all the crop residues), so we don't expect their lower costs to have, individually or collectively, a huge effect on the overall feedstock costs. Thus, we project that for several years, the feedstock costs will be largely a function of the cost to harvest, store, and haul corn stover.

For the crop residues, we relied on the FASOM agricultural cost model for farm harvesting and collection costs. FASOM estimates corn stover would cost $34.49 per dry ton at the farm gate. This reflects the cost to mow, rake, bale, and field haul the bales and replace nutrients. This farm gate cost could be lower if new equipment is developed that would allow the farmer to harvest the corn stover at the same time as the corn. Energy crops such as switchgrass and miscanthus would be harvested, baled, stored and transported in a manner very similar to crop residues. The FASOM model estimates switch grass, which we are using to be representative of all energy crops, would be available at farm side at a cost of $40.85.

Forestry Residue

Harvest and transport costs for woody biomass in its different forms vary due to tract size, tree species, volumes removed, distance to the wood-using/storage facility, terrain, road condition, and other many other considerations. There is a significant variation in these factors within the United States, so timber harvest and delivery systems must be designed to meet constraints at the local level. Harvesting costs also depend on the type of equipment used, season in which the operation occurs, along with a host of other factors. Much of the forest residue is already being harvested by logging operations, or is available from milling operations. However, the smaller branches and smaller trees proposed to be used for biofuel production are not collected for their lumber so they are normally left behind. Thus, this forest residue would have to be collected and transported out of the forest, and then most likely chipped before transport to the biofuel plant.

In general, most operators in the near future would be expected to chip at roadside in the forest, blowing the chips directly into a chip van. When the van is full it will be hauled to an end user's facility and a new van will be moved into position at the chipper. The process might change in the future as baling systems become economically feasible or as roll-off containers are proven as a way to handle logging slash. At present, most of the chipping for biomass production is done in connection with forest thinning treatments as part of a forest fire prevention strategy. The major problem associated with collecting logging residues and biomass from small trees is handling the material in the forest before it gets to the chipper. Specially-built balers and roll-off containers offer some promise to reduce this cost. Whether the material is collected from a forest thinning operation or a commercial logging operation, chips from residues will be dirty and will require screening or some type of filtration at the end-user's facility.[307]

As with agricultural residues and energy crops we relied on the FASOM model for road side costs for forestry residue. The FASOM model estimates costs for both hardwood and softwood logging residues. We anticipate that forestry residue for the production of cellulosic biofuels would be a mixture of both hard and soft woods. In order to obtain a cost for forest residues to be used as a feedstock for cellulosic biofuels we averaged the costs of the hardwood and softwood logging residue prices reported by FASOM. This resulted in a forestry residue price of $20.79 at the roadside. Note that this does not include the cost of the grinding operation that would be required before the forestry residues can be processed by the biofuel producer.

Municipal Solid Waste

Millions of tons of municipal solid waste (MSW) continue to be disposed of in landfills across the country, despite recent large gains in waste reduction and diversion. The biomass fraction of this total stream represents a potentially significant resource for renewable energy (including electricity and biofuels). Because this waste material is already being generated, collected and transported (it would only need to be transported to a different location), its use is likely to be less expensive than other cellulosic feedstocks. One important difficulty facing those who plan to use MSW fractions for fuel production is that in many places, even today, MSW is a mixture of all types of wastes, including biomaterials such as animal fats and grease, tin, iron, aluminum, and other metals, painted woods, plastics, and glass. Many of these materials can't be used in biochemical and thermochemical ethanol production, and, in fact, would inflate the transportation costs, impede the operations at the cellulosic ethanol plant and cause an expensive waste stream for biofuel producers.

In today's regulation the definition of "renewable biomass" includes the separated yard and food waste portion of MSW. As discussed in Section III.B.4.d, we are including as part of separated yard and food waste, incidental and post-recycled paper and wood wastes. Thus, firms planning on using MSW for producing cellulosic biofuels will be required to account for those components of the waste. We offer three methods for performing such accounting. One method is "feedstock accounting" in which the components of the waste stream are inventoried to obtain the fraction representing the portion of the waste stream that qualifies as renewable biomass. The second method is that upon verification that the food and yard waste is reasonably separated, that 100 percent of such waste may be counted as renewable biomass for purpose of generating RINs. Reasonable separation is considered to occur where curbside recycling is implemented, or

[307] Personal Communication, Eini C. Lowell, Research Scientist, USDA Forest Service

where technologies are employed that ensure a maximum degree of separation, including but not limited to material recovery facilities. Under the second method, the renewable portion of the fuel so produced must be verified via a carbon dating method (ASTM D-6866 method) which is specified and incorporated by reference in today's regulation. The third method is the application of a default fraction of 50% to be applied to the waste stream purchased and used by the fuel producer.

One method for sorting that would qualify to ensure reasonable separation has occurred is single stream recycling, in which the waste is sorted either at a sorting facility or at the landfill prior to dumping. There are two prominent options here. The first is that there is no sorting at the waste creation site, the home or business, and thus a single waste stream must be sorted at the facility. The second is that the sorting occurs at the waste collection facility. The sorting would likely be done by hand or by automated equipment at the facility known as material recovery facilities (MRFs). To do so by hand is very labor intensive and somewhat slower than using an automated system. In most cases the 'by-hand' system produces a slightly cleaner stream, but the high cost of labor usually makes the automated system more cost-effective. Perhaps the best approach for low cost and a clean stream is the combination of hand sorting with automated sorting.

Another method is a combination of the two which requires that there is at least some sorting at the home or business which helps to prevent contamination of the waste material, but then the final sorting occurs downstream at a sorting site, or at the landfill.

We have little data and few estimates for the cost to sort MSW. One estimate generated by our Office of Solid Waste for a combination of mechanically and manually sorting a single waste stream downstream of where the waste is generated puts the cost in the \$20 to \$30 per ton range. There is a risk, though, that the waste stream could still be contaminated and this would increase the cost of both transporting the material and using this material at the biofuel plant due to the toxic ash produced which would require disposal at a toxic waste facility. If a less contaminated stream is desired it would probably require sorting at the generation site – the home or business - which would likely be more costly since many more people in society would then have to be involved and special trucks would need to be used. Also, widespread participation is difficult when a change in human behavior is required as some may not be so willing to participate. Offering incentives could help to speed the transition to curbside recycling (i.e., charging a fee for nonsorted waste, or paying a small amount for sorted tree trimmings and construction and demolition waste). Assuming that curbside sorting is involved, at least in a minor way, total sorting costs might be in the \$30 to \$40 per ton range.

These sorting costs would be offset by the cost savings for not disposing of the waste material. Most landfills charge tipping fees, the cost to dump a load of waste into a landfill. In the United States, the national average nominal tipping fee increased fourfold from 1985 to 2000. The real tipping fee almost doubled, up from a national average (in 1997 dollars) of about \$12 per ton in 1985 to just over \$30 in 2000. Equally important, it is apparent that the tipping fees are much higher in densely populated regions and for areas along the U.S. coast. For example, in 2004, the tipping fees were \$9 per ton in Denver and \$97 per ton in Spokane. Statewide averages also varied widely, from \$8 a ton in New Mexico to \$75 in New Jersey. Tipping fees ranged from \$21 to 98 per ton in 2006 for MSW and \$18/ton to \$120/ton for construction and demolition waste. It is likely that the tipping fees are highest for contaminated waste that require the disposal of the waste in more expensive waste sites that can accept the contaminated waste as opposed to a composting site. However, this same contaminated material would probably not be desirable to biofuel producers. Presuming that only the uncontaminated cellulosic waste (yard trimmings, building construction and demolition waste and some paper) is collected as feedstocks for biofuel plants, the handling and tipping fees are likely much lower, in the $30 per ton range.[308]

The wide variance in the cost of many of these areas affecting the final cost of MSW as a cellulosic feedstock, including costs for collecting and sorting MSW as well as the tipping fees for disposing of waste materials, makes approximating the cost of MSW a difficult task. Rather than attempt to build a model ourselves that would estimate the cost of sorted MSW, we decided to contact several companies that are currently planning on using MSW as a feedstock for cellulosic biofuel production. In confidential conversations with these companies they indicated that they believed that sorted MSW would be available at a near zero cost. In one case they had already begun securing MSW sources of feedstock for future biofuel production facilities. They indicated to us that while there would be a significant cost associated with sorting the MSW, this would be offset, or nearly so, by income generated from the sale of recovered materials (paper, metals, plastics, etc.) and the avoidance of tipping fees. There would still, however, be some costs associated with the transportation and disposal of materials unfit for the biofuels production process. Based on this information, we conservatively estimate that MSW would be available for use in a cellulosic biofuel production process at a cost of $15 per ton. See section 4.1 of the RIA for further discussion on the cost of MSW as a feedstock for cellulosic biofuels production.

Secondary Storage and Transportation

In addition to the roadside costs cited in the preceding sections, there will also be a cost to transport the cellulosic materials from the farm or forest to the production facility. We relied on our own cost analysis to determine the transportation costs. For MSW we do not anticipate any additional costs to transport the cellulosic material to the biofuel production facility if it is sourced from within the same county as the production facility. This is because this material is already being collected and transported to a sorting center landfill, and would simply be re-routed to the production facility.

For agricultural residues, energy crops, and forestry residue, however, there will be additional costs associated with transporting them from the farm or forest side to the production facility. These costs are heavily dependent on the distance that the feedstock must be transported from the places where it is produced to the biofuel production facility. In order to estimate these costs we created a cost estimating tool that calculated transportation costs based on the distance the cellulosic material would have to be transported from the farm or forest side to the production facility. This tool relies on data provided by the National Agricultural Statistics Service for information on the availability and location of agricultural residue. Information on abandoned crop land, which was assumed to be the source of energy crops, was provided by Elliot Campbell at UC Davis. Data on the availability and location of forest residues was provided by the national forestry service. For more information on this secondary storage and transportation cost estimating tool that we used to estimate transportation costs see Chapter 4.1 of the RIA.

We also believe that some cellulosic feedstocks will require secondary storage. Agricultural residues and energy crops will generally be harvested annually, sometimes in time periods as short as a few weeks in order to complete the harvest before the onset of winter weather. The large quantity of feedstock required for a commercial scale biofuel production plant makes it highly unlikely that a year's worth of feedstock would be stored at the production

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308 We plan on conducting a more thorough analysis of tipping fees by waste type for the final rulemaking.

facility. It is also unlikely that farmers would tolerate the baled agricultural residues or energy crops to be stored on their farms and transported to the production facility on an as needed basis unless they were compensated for the space bales occupy and damage done to their fields by the heavy traffic that would be involved in the collection of this material from their farms. Bales left exposed to the weather would also decompose much more rapidly resulting in a higher cost per ton of usable cellulosic material to biofuel producers. This loss would be minimized if the bales are stored in covered sheds. Our cost estimating tool takes these secondary storage costs into account for agricultural residues and energy crops. MSW and forestry residues have no secondary storage costs as they can be collected and transported on an as needed basis.

Cellulosic Feedstock Cost Curve

When the various costs described above are combined, together with the cost of grinding the cellulosic material ($11/ton), the result is not a single cost, but rather a cost curve. This is due to the fact that each feedstock source has a unique price based on the FASOM estimate of the cost of production of the feedstock and the cost of transportation and secondary storage (if appropriate), where feedstocks have the lowest total cost in the parts of the country where the cellulosic plants are likely to be located. The cost per ton of feedstock is lower when the total production of cellulosic biofuel is low as the cheapest feedstocks are utilized first. As cellulosic biofuel production increases, so does the cost of cellulosic feedstocks, as more expensive sources of feedstock are used. The cost curve for cellulosic feedstocks for the production of up to 16 billion ethanol equivalent gallons of cellulosic biofuels is shown in Graph VIII.A.1-1 below. The average cost of cellulosic feedstock at a production level of 16 billion ethanol equivalent gallons is $67.42, and is summarized in Table VII.A.1-5.

Figure VII.A.1-1
Cellulosic Feedstock Cost Curve

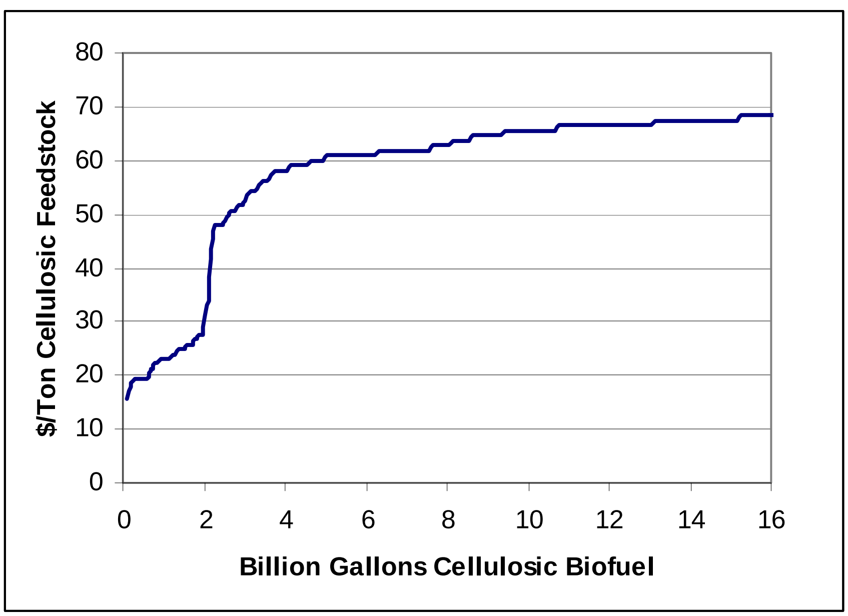

Table VII.A.1-5
Summary of Cellulosic Feedstock Costs

Ag Residue	Switchgrass	Forest Residue	MSW
36% of Total Feedstock	49% of total Feedstock	1% of Total Feedstock	15% of Total Feedstock
Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $34.49/ton	Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $40.85/ton	Harvesting, Hauling to Forest Edge, $20.79/ton	Sorting, Contaminant Removal, Tipping Fees Avoided $15/ton
Hauling to Secondary Storage, Secondary Storage, Hauling to Plant $21.53/ton (average)			
Grinding $11/ton			
Total $67.42/ton			

ii. *Production Costs for Cellulosic Biofuels*

In this section, we discuss the cost to biochemically and thermochemically convert cellulosic feedstocks into fuel ethanol.

Biochemical Ethanol

The National Renewable Energy Laboratory has been evaluating the state of biochemical cellulosic plant technology over the past decade or so, and it has identified principal areas for improvement. In 1999, it released its first report on the likely design concept for an nth generation biochemical cellulosic ethanol plant which projected the state of technology in some future year after the improvements were adopted. In 2002, NREL released a follow-up report which delved deeper into biochemical plant design in areas that it had identified in the 1999 report as deserving for additional research. Again, the 2002 report estimated the ethanol production cost for an nth generation biochemical cellulosic ethanol plant. These reports not only helped to inform policy makers on the likely capability and cost for biochemically converting cellulose to ethanol, but it helped to inform biochemical technology researchers on the most likely technology improvements that could be incorporated into these plant designs.

To comply with the RFS 2 requirements, NREL assessed the likely state of biochemical cellulosic plant technology for EPA over the years that the RFS standard is being phased in. The specific years assessed by NREL were 2010, 2015 and 2022. The year 2010 technology essentially represents the status of today's biochemical cellulosic plants. The year 2015 technology captures the expected near-term improvements including the rapid improvements being made in enzyme technology. The year 2022 technology captures the cost of mature biochemical cellulosic plant technology. Table VII.A.1-6 summarizes NREL's estimated and projected production costs for biochemical cellulosic ethanol plant technology for their projected year 2022 technology in 2007 dollars reflecting a 7 percent before tax rate of return on investment. The biochemical cellulosic ethanol costs are based on a cellulosic feedstock cost of 67 per dry ton.

Table VII.A.1-6
Year 2022 Biochemical Cellulosic Ethanol Production Costs
Provided by NREL (2007 dollars and 7% before tax rate of return)

Year Technology	2022	
Plant Size MMgal/yr	71	
Capital Cost $MM	199	
$MM/yr		c/gal
Capital Cost 7% ROI before taxes	22 31	
Fixed Costs	8	12
Feedstock Cost	52	73
Other raw matl. costs	12 16	
Enzyme Cost	5	8
Enzyme nutrients	2 2	
Electricity -12		-16
Waste disposal	1	1
Total Costs	90	127

Thermochemical Ethanol

Thermochemical conversion is another reaction pathway which exists for converting cellulose to ethanol. Thermochemical technology is based on the heat and pressure-based gasification or pyrolysis of nearly any biomass feedstock, including those we've highlighted as likely biochemical feedstocks. The syngas could then be converted into mixed alcohols, hydrocarbon fuels, chemicals, and power. In the case that the syngas is converted to ethanol, a possible means for doing so would be to pass the syngas over a catalyst which converts the syngas to mixed alcohols – mainly methanol. The methanol can be reacted further to ethanol.

NREL has authored a thermochemical report: Phillips, S Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass; April, 2007, which already provided a cost estimate. However, this report only hypothesized how a thermochemical ethanol plant could achieve production costs at a very low cost of $1 per gallon. Rather than rely on a very aggressively analyzed cost assessment that may not be achievable within the timeframe of our program, EPA contracted NREL to assess the costs for a thermochemical technology which produces mixed alcohols for years 2010, 2015 and 2022. Table VII.A.1-7 summarizes NREL's estimated and projected production costs for biochemical cellulosic ethanol plant technology for their projected year 2022 technology in 2007 dollars reflecting a 7 percent before tax rate of return on investment. The costs are based on a cellulosic feedstock cost of 67 per dry ton.

Table VII.A.1-7
Year 2022 Thermochemical Cellulosic Production Costs of Mixed Alcohols
Provided by NREL (2007 dollars and 7% before tax rate of return)

Year Technology	2022	
Plant Size MMgal/yr	72.7 Total Alcohol 61.9 Ethanol	
Capital Cost $MM	207	
$MM/yr		c/gal
Capital Cost 7% ROI before taxes	23 37	
Fixed Costs	13	21
Feedstock Cost	52	85
Coproduct Credit	-13 -21	
Other Raw Material, Waste Disposal and Catalyst Costs	1 4	
Total Costs	76	126

Cost estimates for both biochemical and thermochemical ethanol pathways ended up being ultimately identical. For our cost analysis, we based the cellulosic ethanol costs on the average of the biochemical and thermochemical cellulosic ethanol costs.

BTL Diesel Fuel

If cellulose is converted to syngas, rather than converting the syngas to mixed alcohols, a Fischer Tropsch reactor can be added to convert the syngas to diesel fuel and naphtha. This technology is commonly termed biomass-to-liquids (BTL) because of its similarity to gas-to-liquids and coal-to-liquids technology. Diesel fuel's higher energy density per gallon than ethanol and even biodiesel provides it an inherent advantage over these other fuels. In addition, BTL diesel fuel can be more easily distributed from production to retail outlets and used by motor vehicles. The diesel fuel produced by the Fischer Tropsch process tends to be comprised of paraffins which provide a much higher cetane number than petroleum diesel fuel, with a downside of poorer cloud point which reduces its widespread use in cold temperatures.

The naphtha produced by the BTL process is also largely comprised of paraffins, however, as a gasoline blendstock it is poor because of its very low octane (potentially as low as

50 octane). This material could be processed by refinery isomerization units raising its octane to perhaps 70 octane, but it cannot be processed by refinery reformers since it does not contain the naphthenic compounds that are necessary for octane improvement by those units. Because of the large amount of octane rich ethanol which is expected to be made available from both corn and cellulose, it could be that BTL naphtha could be blended along with the ethanol into the gasoline pool. Rather than prejudge how this naphtha may be utilized in the future, for our cost analysis we simply assigned it a coproduct credit. So we set the BTL naphtha cost to be 83% as much of the cost of BTL diesel fuel based on its relative energy density.

Although there were several studies available which provided costs estimates for BTL diesel fuel, they did not provide sufficient detail to understand all the cost elements of BTL diesel fuel and naphtha. EPA therefore asked NREL to estimate the production costs for BTL diesel fuel and naphtha. Like the other technologies, we asked for cost estimates for the same years assessed above for cellulosic ethanol which was for 2010, 2015 and 2022, however, NREL did not believe that the costs would change that much over this time span. So NREL only provided the costs for 2022, advising us that the costs would only be slightly less for earlier years, and most of that difference would because of the poorer economies of scale for the initial smaller sized plants.

Table VII.A.1-8 summarizes NREL's estimated and projected production costs for a thermochemical Fischer Tropsch biochemical cellulosic ethanol plant technology for their projected year 2022 technology in 2007 dollars reflecting a 7 percent before tax rate of return on investment. The costs are based on a cellulosic feedstock cost of 67 per dry ton.

Table VII.A.1-8
Year 2022 Production Costs of Thermochemical (BTL) Cellulosic Fischer Tropsch Diesel Fuel Provided by NREL (2007 dollars and 7% before tax rate of return)

Plant Size MMgal/yr	33.2 Diesel Fuel 49.4 All Liquid
Capital Cost $MM	346
Capital Cost 7% ROI before taxes ($MM/yr)	38
Fixed Costs ($MM/yr)	18
Feedstock Cost ($MM/yr)	52
Coproduct Credit ($MM/yr)[a] -32	
Other raw matl. Costs ($MM/yr)	1.5
Waste Disposal and Catalyst Costs ($MM/yr)	1.5
Total Costs ($MM/yr)	79
Total Costs (cents/gallon of diesel fuel)	237

a Based on a naphtha coproduct value of 198 cents per gallon.

Other Cellulosic Diesel Fuel Costs

For our volumes analysis, we assumed early on for our final rule analysis that there would likely be several different cellulosic biofuel technologies, other than BTL, producing cellulosic diesel fuel. However, we were either not able to obtain cost information from them, or we were uncertain enough about their future that we felt that we should not base the cost of the program on them. For example, Cello Energy has already built a cellulosic diesel fuel facility in Alabama here in the US with projected costs of about one dollar per gallon of diesel fuel.

However, the facility has had difficulty operating as designed. As a result, perhaps very conservatively, we assumed that the other cellulosic diesel fuel costs would be the same as the BTL diesel fuel costs, and used the 237 cents per gallon cost for BTL diesel fuel for the entire cost for cellulosic diesel fuel.

c. Imported Sugarcane Ethanol

We based our imported ethanol fuel costs on cost estimates of sugarcane ethanol in Brazil. Generally, ethanol from sugarcane produced in developing countries with warm climates is much cheaper to produce than ethanol from grain or sugar beets. This is due to favorable growing conditions, relatively low cost feedstock and energy inputs, and other cost reductions gained from years of experience.

As discussed in Chapter 4 of the RIA, our literature search of production costs for sugar cane ethanol in Brazil indicates that production costs tend to range from as low as $0.57 per gallon of ethanol to as high as $1.48 per gallon of ethanol. This large range for estimating production costs is partly due to the significant variations over time in exchange rates, costs of sugarcane and oil products, etc. For example, earlier estimates may underestimate current crude and natural gas costs which influence the cost of feedstock as well as energy costs at the plant. Another possible difference in production cost estimates is whether or not the estimates are referring to hydrous or anhydrous ethanol. Costs for anhydrous ethanol (for blending with gasoline) are typically several cents per gallon higher than hydrous ethanol (for use in dedicated ethanol vehicles in Brazil).[309] It is not entirely clear from the majority of studies whether reported costs are for hydrous or anhydrous ethanol. Yet another difference could be the slate of products the plant is producing, for example, future plants may be dedicated ethanol facilities while others involve the production of both sugar and ethanol in the same facility. Due to economies of scale, production costs are also typically smaller per gallon for larger facilities.

The study by OECD (2008) entitled "Biofuels: Linking Support to Performance", appears to provide the most recent and detailed set of assumptions and production costs. As such, our estimate of sugarcane production costs primarily relies on the assumptions made for the study, which are shown in Table VII.A.1-9. The estimate assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh.

[309] International Energy Agency (IEA), "Biofuels for Transport: An International Perspective," 2004.

Table VII.A.1-9
Cost of Production in a Standard Ethanol Project in Brazil

Sugarcane Productivity	71.5 t/ha
Sugarcane Consumption	2 million tons/year
Harvesting days	167
Ethanol productivity	85 liters/ton (22.5 gal/ton)
Ethanol Production	170 million liters/year (45 MGY)
Surplus power produced	40 kWh/ton sugarcane
Investment cost in mill	USD 97 million
Investment cost for sugarcane production	USD 36 million
O & M (Operating & Maintenance) costs	$0.26/gal
Variable sugarcane production costs	$0.64/gal
Capital costs	$0.49/gal
Total production costs	$1.40/gal

The estimate above is based on the costs of producing ethanol in Brazil on average, today. However, we are interested in how the costs of producing ethanol will change by the year 2022. Although various cost estimates exist, analysis of the cost trends over time shows that the cost of producing ethanol in Brazil has been steadily declining due to efficiency improvements in cane production and ethanol conversion processes. Between 1980 and 1998 (total span of 19 years) ethanol cost declined by approximately 30.8%.[310] This change in the cost of production over time in Brazil is known as the ethanol cost "Learning Curve".

The change in ethanol costs will depend on the likely productivity gains and technological innovations that can be made in the future. As the majority of learning may have already occurred, it is likely that the decline in sugarcane ethanol costs will be less drastic in the future as the production process and cane practices have matured. Industrial efficiency gains are already at about 85% and are expected to increase to 90% in 2015.[311] Most of the productivity growth is expected to come from sugarcane production, where yields are expected to grow from the current 70 tons/ha, to 96 tons/ha in 2025.[312] Sugarcane quality is also expected to improve, with sucrose content growing from 14.5% to 17.3% in 2025.[313] All productivity gains together could allow the increase in the production of ethanol from 6,000 liters/ha (at 85 liters/ton sugarcane in 2005) to 10,400 liters/ha (at 109 liters/ton sugarcane) by 2025.[314] Although not reflected here, there could also be cost and efficiency improvements related to feedstock collection, storage, and distribution.

Assuming that ethanol productivity increases to 100 liters/ton by 2015 and 109 liters/ton by 2025, variable sugarcane ethanol production costs are be expected to decrease to approximately $0.51/gal from $0.64/gal since less feedstock is needed to produce the same

[310] Goldemberg, J. as sited in Rothkopf, Garten, "A Blueprint for Green Energy in the Americas," 2006.
[311] Unicamp "A Expansão do Proalcool como Programa de Desenvolvimento Nacional". Powerpoint presentation at *Ethanol Seminar* in BNDES, 2006. As sited in OECD, "Biofuels: Linking Support to Performance," ITF Round Tables No. 138, March 2008.
[312] *Ibid*.
[313] *Ibid*.
[314] *Ibid*.

volume of ethanol using the estimates from Table VII.A.1-7, above. We assumed a linear decrease between data points for 2005, 2015, and 2025. Adding operating ($0.26/gal) and capital costs ($0.49/gal) from Table VII.A.1-7, to a sugarcane cost of $0.51/gal, total production costs are $1.26/gal in 2022.

Brazil sugarcane producers are also expected to move from burned cane manual harvesting to mechanical harvesting. As a result, large amounts of straw are expected to be available. Costs of mechanical harvesting are lower compared to manually harvesting, therefore, we would expect costs for sugarcane to decline as greater sugarcane producers move to mechanical harvesting. However, diesel use increases with mechanical harvesting and with diesel fuel prices expected to increase in the future, costs may be higher than expected. Therefore, we have not assumed any changes to harvesting costs due to the switchover from manual harvesting to mechanical harvesting.

As more straw is expected to be collected at future sugarcane ethanol facilities, there is greater potential for production of excess electricity. The production costs estimates in the OECD study assumes an excess of 40 kWh per ton sugarcane, however, future sugarcane plants are expected to produce 135 kWh per ton sugarcane assuming the use of higher efficiency condensing-extraction steam turbine (CEST) systems and use of 40% of available straw.[315] Assuming excess electricity is sold for $57 per MWh, the production of 95 kWh per ton would be equivalent to a credit of $0.22 per gallon ethanol produced. We have included this potential additional credit from greater use of bagasse and straw in our estimates at this time, calculated as a decrease in operating costs from $0.26 per gallon to $0.04 per gallon.

It is also important to note that ethanol production costs can increase if the costs of compliance with various sustainability criteria are taken into account. For instance, using organic or green cane production, adopting higher wages, etc. could increase production costs for sugarcane ethanol.[316] Such sustainability criteria could also be applicable to other feedstocks, for example, those used in corn- or soy-based biofuel production. If these measures are adopted in the future, production costs will be higher than we have projected.

In addition to production costs, there are also logistical and port costs. We used the report from AgraFNP to estimate such costs since it was the only resource that included both logistical and port costs. The total average logistical and port cost for sugarcane ethanol is $0.20/gal and $0.09/gal, respectively, as shown in Table VII.A.1-10.

Table VII.A.1-10
Imported Ethanol Cost at Port in Brazil (2006 $)

Region US	Logistical Costs ($/gal)	Port Cost US ($/gal)
NE Sao Paulo	0.150	0.097

[315] Macedo. I.C., "Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 Averages and a Prediction for 2020," *Biomass and Bioenergy*, 2008.
[316] Smeets E, Junginger M, Faaij A, Walter A, Dolzan P, Turkenburg W, "The sustainability of Brazilian ethanol-An Assessment of the possibilities of certified production," *Biomass and Bioenergy*, 2008.

W Sao Paulo	0.210	0.097
SE Sao Paulo	0.103	0.097
S Sao Paulo	0.175	0.097
N Parana	0.238	0.097
S Goias	0.337	0.097
E Mato Grosso do sul	0.331	0.097
Triangulo mineiro	0.207	0.097
NE Cost	0.027	0.060
Sao Francisco Valley	0.193	0.060
Average 0.197		0.089

Total fuel costs must also include the cost to ship ethanol from Brazil to the U.S. The average cost from 2006-2008 was estimated to be approximately $0.17 per gallon of ethanol.[317] Costs were estimated as the difference between the unit value cost of insurance and freight (CIF) and the unit value customs price. The average cost to ship ethanol from Caribbean countries (e.g. El Salvador, Jamaica, etc.) to the U.S. from 2006-2008 was approximately $0.13 per gallon of ethanol. Although this may seem to be an advantage for Caribbean countries, it should be noted that there would be some additional cost for shipping ethanol from Brazil to the Caribbean country. Therefore, we assume all costs for shipping ethanol to be $0.17 per gallon regardless of the country importing ethanol to the U.S.

Total imported ethanol fuel costs (at U.S. ports) prior to tariff and tax for 2022 is shown in Table VII.A.1-11, at $1.50/gallon. Direct Brazilian imports are also subject to an additional $0.54 per gallon tariff, whereas those imports arriving in the U.S. from Caribbean Basin Initiative (CBI) countries are exempt from the tariff. In addition, all imports are given an ad valorem tax of 2.5% for undenatured ethanol and a 1.9% tax for denatured ethanol. We assumed an ad valorem tax of 2.5% for all ethanol. Thus, including tariffs and ad valorem taxes, the average cost of imported ethanol is shown in Table VII.A.1-12 in the “Brazil Direct w/ Tax & Tariff” and “CBI w/ Tax” columns for 2022.

[317] Official Statistics of the U.S. Department of Commerce, USITC

Table VII.A.1-11
Average Imported Ethanol Costs Prior to Tariff and Taxes in 2022

Sugarcane Production Cost ($/gal)	Operating Cost ($/gal)	Capital Cost ($/gal)	Logistical Cost ($/gal)	Port Cost ($/gal)	Transport Cost from Port to US ($/gal)	Total Cost ($/gal)
0.51	0.04 0.49	0.20		0.09	0.17	1.50

Table VII.A.1-12
Average Imported Ethanol Costs in 2022

Brazil Direct ($/gal)	Brazil Direct w/ Tax & Tariff ($/gal)	CBI ($/gal)	CBI w/ Tax ($/gal)
1.50 2.08		1.50	1.54

2. Biodiesel and Renewable Diesel Production Costs

Biodiesel and renewable diesel production costs are primarily a function of the feedstock cost, and to a much lesser extent, the capital and other operating costs of the facility.

a. Biodiesel

Biodiesel production costs for this rule were estimated using two versions of a biodiesel production facility model obtained from USDA, one using degummed soy oil as a feedstock and the other using yellow grease. The biodiesel from yellow grease model includes acid pre-treatment steps required to utilize feedstocks with high free fatty acid content.

The production model simulates a 10 million-gallon-per-year plant operating a continuous flow transesterification process. USDA used the SuperPro Designer chemical process simulation software to estimate heat and material flowrates and equipment sizing. Outputs from this software were then combined in a spreadsheet with equipment, energy, labor, and chemical costs to generate a final estimate of production cost. The model is described in a 2006 publication in Bioresource Technology, peer-reviewed scientific journal. [318] For the purpose of estimating biodiesel production cost for this rulemaking, a model with updated facility, labor, and chemical costs was used. Installed capital cost was $11.9 million, and energy prices were taken from AEO 2009: natural gas at $7.75/MMBtu and electricity at $0.066/kWh. Capital charge plus maintenance was assumed to be 14% of total capital per year. Table VII.A.2-1 shows the production cost allocation for the soy oil-to-biodiesel facility as modeled in the 2022 policy case.

[318] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

Table VII.A.2-1
Production Cost Allocation for Soy Biodiesel for Policy Case in 2022

Cost Category	Contribution to Cost
Soy Oil	85%
Other Materials [a] 6%	
Capital & Facility	6%
Labor 2%	
Utilities 2%	

[a] Includes acids, bases, methanol, catalyst

Soy oil costs were generated by the FASOM agricultural model (described in more detail in Section VIII.A). Historically, the majority of biodiesel production in the U.S. has used soy oil, a relatively high-value feedstock, but a growing fraction of biodiesel is being made from yellow grease (rendered or reclaimed oil that is not suitable for use in food products). This material has historically sold for about 70% of the value of virgin soy oil. However, conversion of yellow grease into biodiesel requires an additional acid pre-treatment step, and therefore the processing costs are higher than for virgin soy oil (40-50 cents/gal if feedstock costs are equal), reducing the attractiveness of the cheaper feedstock to some extent. Another feedstock we expect to be used in significant quantities in the future is distressed corn oil extracted from process streams that make up distillers' grains. This material will also require processing in acid pre-treatment facilities, and is projected by the FASOM model to have about one half the value of soy oil.

Finally, we project a small amount of algae-derived oil (or similarly advanced feedstock) will be used by 2022. As algal biofuel technology is still in a relatively early stage of development, there are many possible configurations for the production of this material and thus there is considerable uncertainty regarding process performance and cost. Based on work done by NREL at the time of this rulemaking, we assumed a production cost of $0.68/lb for this feedstock. [319] More details on how this estimate was made can be found in Chapter 4.1 of the RIA.

A co-product of transesterification is crude glycerin. With the upswing in worldwide biodiesel production in recent years, its price has been depressed in most markets. Closure of remaining petrochemical glycerin plants, along with development of processes to make new use of it as a feedstock for other commodity chemicals has provided some support for a price recovery. Some companies are experimenting with using glycerin as a fuel for process or facility heat. We expect new uses for this coproduct to continue growing to reach an equilibrium with supply at or near its heating value, which we estimate to be $0.15/lb. As a result, the sale of this material as a co-product reduces biodiesel production cost by about $0.13/gal in our control case.

b. Renewable Diesel

Renewable diesel production can occur in a few different configurations: within the boundaries of an existing refinery where it may or may not be coprocessed with petroleum, or at

[319] See Technical Memo in the docket entitled "Techno-economic analysis of microalgae-derived biofuel production" by Ryan Davis of the National Renewable Energy Laboratory.

a stand-alone plant that may or may not be co-located with other facilities that provide utilities or hydrogen. Given changes in the tax incentives as well as current project announcements, we have chosen to project that all renewable diesel will be produced in stand-alone facilities, not coprocessing with petroleum. The 75 MMgal/yr Syntroleum facility scheduled to come online in Geismar, Louisiana, in 2010 is an example of such a plant.

Our production cost estimates used hydrogen requirements made available publicly by UOP, Inc. and overall project cost of $150MM taken from Syntroleum, Corp. materials. [320, 321] The feedstock was assumed to be yellow grease or similar rendered material. Hydrogen and co-product prices were taken from refinery modeling done for this rule, while an aggregate figure of $0.069/gal, derived from the UOP publication, was used to cover other variable operating costs besides hydrogen (includes labor, catalyst, and utilities). Cost contributions of various process aspects are shown in Table VII.A.2-2. More details are available in Chapter 4.1 of the RIA.

Table VII.A.2-2
Production Cost Allocation for Renewable Diesel for Policy Case in 2022

Cost Category	**Contribution to Cost**
Feedstock 78%	
Capital & Facility	11%
Hydrogen 7%	
Other variable costs	3%

Table VII.A.2-3 summarizes the production costs for biodiesel and renewable diesel as estimated for this rule, as well as their projected volume contribution in 2022. Biodiesel made from yellow grease is projected to be about 10% cheaper to produce despite its higher production cost due to the large influence of the feedstock cost, which is about 30% lower. Biodiesel from extracted corn oil is expected to be significantly cheaper to produce than this, again due to the projected feedstock cost being about half that of soy oil. Finally, renewable diesel from stand-alone production is estimated in this analysis to have total production cost similar to biodiesel from yellow grease. However, given the business partnership between the fuel production and animal processing companies who have announced or are constructing the U.S. plants to date, we expect the feedstock being used there may be made available at a lower cost than we are projecting here for yellow grease.

[320] A New Development in Renewable Fuels: Green Diesel, AM-07-10 Annual Meeting NPRA, March 18-20, 2007.
[321] Taken from Syntroleum Investor Presentation, November 5, 2009. See http://www.syntroleum.com/Presentations/SyntroleumInvestorPresentation.November%205.2009.FINAL.pdf

Table VII.A.2-3
Summary of Cost for Biodiesel and Renewable Diesel for Policy Case in 2022
(2007$)

Fuel / Feedstock	**Feedstock Price ($/lb)**	**Fuel Production Cost ($/gal)**
Biodiesel / soy oil	0.33 [a] 2.73	
Biodiesel / corn oil extraction at ethanol plants	0.17 [a] 1.90	
Biodiesel / yellow grease or other rendered fats	0.23 [b] 2.43	
Biodiesel / algae or other advanced virgin oil feedstock	0.58 [c] 4.52	[d]
Renewable diesel / yellow grease or other rendered fats	0.23 [b] 2.42	

[a] Taken from outputs of FASOM model.
[b] Derived from outputs of FASOM model, assuming 70% value of soy oil.
[c] Derived from figures in a Technical Memo by Ryan Davis of NREL entitled "Techno-economic analysis of microalgae-derived biofuel production" (available in docket).
[d] This production cost assumes this advanced feedstock has very low free fatty acid content.

B. Biofuel Distribution Costs

Our analysis of the costs associated with distributing the volume of biofuels that we project will be used under RFS2 focuses on: 1) the capital cost of making the necessary upgrades to the fuel distribution infrastructure system directly related to handling these fuels, and 2) the ongoing additional freight costs associated with shipping renewable fuels to the point where they are blended with petroleum-based fuels.[322] The following sections outline our estimates of the distribution costs for the additional volumes of ethanol, cellulosic distillate fuel, renewable diesel fuel, and biodiesel that we project would be used in response to the RFS2 standards under the three control scenarios that we analyzed relative to the two reference cases.[323]

A discussion of the capability of the transportation system to accommodate the volumes of renewable fuels projected to be used under RFS2 is contained in Section IV.C. of today's preamble and 1.6 of the RIA. There will be ancillary costs associated with upgrading the basic rail, marine, and road transportation nets to handle the increase in freight volume due to the RFS2. We have not sought to quantify these ancillary costs because 1) the growth in freight traffic that is attributable to RFS2 represents a small fraction of the total anticipated increase in freight tonnage (approximately 3% of rail traffic by 2022, see Section IV.C.1), and 2) we do not believe there is an adequate way to estimate such non-direct costs.

1. Ethanol Distribution Costs

[322] The anticipated ways that the renewable fuels projected to be used in response to the EISA will be distributed is discussed in Section IV.C. of today's preamble.
[323] Please refer to Section 4.2 of the RIA for additional discussion of how these estimates were derived.

The capital costs to upgrade the distribution system to handle the increased volumes of ethanol vary substantially under the three control scenarios that we analyzed. Table VII.B.1-1 contains our estimates of the fuel distribution infrastructure capital costs to support the use of the additional ethanol that we project will be used under the three use scenarios by 2022 relative to the RFS1 reference case forecast of 7.05 BGY.[324] The total estimated capital costs under our primary case are estimated at $7.90 billion which when amortized equates to approximately 6 cents per gallon of the additional ethanol volume that would be used in 2022 in response to the RFS2 standards relative to the RFS1 reference case.[325] Capital costs under the low-ethanol and high-ethanol scenarios are estimated at $5.47 billion and $11.92 billion respectively. This equates to 6 and 5 cents per gallon respectively relative to the RFS1 reference case.

Table VII.B.1-1
Estimated Ethanol Distribution Infrastructure Capital Costs
Under the RFS1 Reference Case

	Million $		
	Low-Ethanol Scenario	Primary Scenario	High-Ethanol Scenario
Fixed Facilities			
Marine Import Facilities	49	53	63
Marine Facilities for Shipment Inside US	98	130	186
Unit Train Receipt Facilities	444	586	838
Manifest Rail Receipt Facilities	15	20	28
Petroleum Terminals			
Terminal Storage Tanks	859	1,243	2,073
Blending & Misc. Equipment	1,006	1,064	1,144
E85 Retail	1,957	3,293	4,973
Mobile Facilities			
Rail Cars	884	1,279	2,218
Barges	53	77	133
Tank Trucks	107	154	268
Total Capital Costs (Million $)	5,471	7,898	11,922
Total Capital Costs (cents per gallon ethanol)	6 6		5

Table VII.B.1-2 contains our estimates of the fuel distribution infrastructure costs to support the use of the additional ethanol that we project will be used under the three use scenarios by 2022 relative to the AEO reference case forecast of 13.18 BGY. The total estimated capital costs under our primary case are estimated at $5.50 billion which when amortized equates

[324] See Section IV.C. of today's preamble for discussion of the upgrades we project will be needed to the distribution system to handle the increase in ethanol volumes under EISA. The derivation of these estimates is discussed in Section 4.2 of the RIA.
[325] These capital costs will be incurred incrementally through 2022 as ethanol volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

to approximately 7 cents per gallon of the additional ethanol volume that would be used in 2022 in response to the RFS2 standards relative to the AEO reference case. Capital costs under the low-ethanol and high-ethanol scenarios are estimated at $3.02 billion and $9.93 billion respectively. This equates to 8 and 6 cents per gallon respectively relative to the AEO reference case.

Table VII.B.1-2
Estimated Ethanol Distribution Infrastructure Capital Costs
Under the AEO Reference Case

	Million $		
	Low-Ethanol Scenario	Primary Scenario	High-Ethanol Scenario
Fixed Facilities			
Marine Import Facilities	49	53	63
Marine Facilities for Shipment Inside US	76	100	144
Unit Train Receipt Facilities	238	434	748
Manifest Rail Receipt Facilities	7	12	21
Petroleum Terminals			
Terminal Storage Tanks	355	739	1,568
Blending & Misc. Equipment	345	411	503
E85 Retail	1,526	2,863	4,893
Mobile Facilities			
Rail Cars	309	522	1,133
Barges	16	28	63
Tank Trucks	68	103	194
Total Capital Costs (Million $)	3,025	5,505	9,935
Total Capital Costs (cents per gallon ethanol)	8 7		6

We estimate that ethanol freight costs under the primary and high-ethanol scenarios would be 13 cents per gallon on a national average basis. Ethanol freight costs under the high-ethanol scenario are estimated at 12 cents per gallon. These estimates are based on an analysis conducted for EPA by Oak Ridge National Laboratory (ORNL) which were modified to reflect projected higher transportation fuel costs in the future, the likely installation of fewer unit train receipt facilities than that projected by ORNL based on industry comments, and to conform to the ethanol volumes under the three control scenarios analyzed in today's rule.[326] The ORNL analysis contains detailed projections of which transportation modes and combination of modes (e.g. unit train to barge) are best suited for delivery of ethanol to specific markets considering ethanol source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes.

[326] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints", prepared for EPA by Oak Ridge National Laboratory, March 2009. The ORNL analysis indicates that ethanol freight costs decrease somewhat with increasing ethanol volume. See Section 4.2 of the RIA for additional discussion of the estimation of ethanol freight costs.

Summing the freight and capital costs estimates results in an estimate of 19 cents per gallon for ethanol distribution costs for our primary and low-ethanol scenarios under the RFS1 reference case. Total ethanol distribution costs under the RFS1 reference case for the high-ethanol scenario are estimated at 17 cents per gallon. Under the AEO reference case, total ethanol distribution costs are estimated at 21, 20, and 18 cents per gallon respectively for the low-ethanol, primary, and high-ethanol scenarios.

As discussed in Section IV.C. of today's preamble, ASTM International is considering a change to specification on the minimum ethanol content in E85 to facilitate the manufacture of E85 at terminals which meets minimum volatility specifications using commonly-available finished gasoline. If the current difficulties in blending E85 to meet minimum volatility specifications can not be resolved by lowering the minimum ethanol concentration of E85, high vapor pressure blendstocks will need to be supplied to approximately two thirds of petroleum terminals for blending with E85.[327] This would necessitate the installation of new blending/storage equipment at petroleum terminals and additional butane tank cars and tank trucks. The capital costs for such facilities would be \$2.2 billion, \$1.4 billion, and \$0.6 billion under the high-ethanol, primary, and low-ethanol scenarios respectively under both reference cases. By amortizing these capital costs and adding in butane freight costs, we estimate that the need to supply special blendstocks at terminals for E85 blending would add approximately 1 cent per gallon to ethanol distribution costs for all three analysis scenarios relative to the RFS1 reference case. Relative to the AEO reference case, the additional cost would be approximately 2 cents per gallon under the primary and low-ethanol scenarios, and approximately 1 cent per gallon under the high-ethanol scenario.

In the NPRM, we estimated that half of the new ethanol rail receipt capability needed to support the use of the projected ethanol volumes under the EISA would be installed at petroleum terminals, and half would be installed at rail terminals. Based on input from industry and a study conducted for us by ORNL, we now believe that all unit train receipt facilities will be installed at new dedicated locations.[328] This change results in the need for additional tank truck receipt equipment at terminals and additional tank trucks to carry ethanol from rail to petroleum terminals compared to the NPRM. However, we also received additional input from industry on the cost of unit train facilities which indicates that such facilities are not as costly as we projected in the NPRM. We also increased the average E85 facility cost relative to the NPRM to reflect the likely need for additional E85 dispensers and a larger underground storage tank to maintain sufficient throughput per facility.[329]

2. Cellulosic Distillate and Renewable Diesel Distribution Costs

We chose to evaluate the distribution costs for cellulosic distillate and renewable diesel together because the same considerations apply to their handling in the fuel distribution system and because the projected volume of renewable diesel fuel is relatively small.

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[327] If this is the case, EPA would need to reconsider its policies regarding what blendstocks can be used at petroleum terminals in the manufacture of E85.
[328] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints", prepared for EPA by Oak Ridge National Laboratory (ORNL), March 2009.
[329] This is a sensitivity case that was evaluated in the NPRM.

Table VII.B.2-1 contains our estimates of the fuel distribution infrastructure capital costs to support the use of the cellulosic distillate and renewable diesel fuel that we project will be used under the three use scenarios by 2022 under the RFS1 reference case.[330] The total estimated capital costs by 2022 under our primary and low-ethanol scenarios are estimated at $1.38 billion and $2.00 billion respectively under the RFS1 reference case.

Table VII.B.2-1
Estimated Cellulosic Distillate Fuel Distribution Infrastructure Capital Costs
Under the RFS1 Reference Case

	Million $		
	Low-Ethanol Scenario	Primary Scenario	High-Ethanol Case
Fixed Facilities			
Marine Facilities for Shipment Inside US	87	56	-
Unit Train Receipt Facilities	394	253	-
Manifest Rail Receipt Facilities	13	8	-
Petroleum Terminals			
Terminal Storage Tanks	218	154	-
Blending & Misc. Equipment	361	252	-
Mobile Facilities			
Rail Cars	784	552	-
Barges	47	33	-
Tank Trucks	95	-	-
Total Capital Costs (Million $)	1,999	1,375	NA
Total Capital Costs (cents per gallon of cellulosic distillate fuel)	2 2		NA

Table VII.B.2-2 contains our estimates of the infrastructure changes and associated capital costs to support the use of the cellulosic distillate and renewable diesel fuel that we project will be used under the three use scenarios by 2022 under the AEO reference case. Total capital costs are estimated at $1.02 and $1.46 billion for the primary and low-ethanol scenarios respectively under the AEO reference case. The difference in estimated capital costs for the two control scenarios under the two reference scenarios is obscured by rounding when translating these costs to a cents-per-gallon basis. When amortized, these capital costs equate to approximately 2 cents per gallon for both control scenarios under both reference cases.[331]

[330] See Section IV.C. of today's preamble for discussion of the upgrades we project will be needed to the distribution system to handle the increase in ethanol volumes under EISA. The derivation of these estimates is discussed in Section 1.6 of the RIA.
[331] These capital costs will be incurred incrementally through 2022 as ethanol volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

Table VII.B.2-2
Estimated Cellulosic Distillate Fuel Distribution Infrastructure Capital Costs
Under the AEO Reference Case

	Million $		
	Low-Ethanol Scenario	Primary Scenario	High-Ethanol Case
Fixed Facilities			
Marine Facilities for Shipment Inside US	67	43	-
Unit Train Receipt Facilities	511	315	-
Manifest Rail Receipt Facilities	15	9	-
Petroleum Terminals			
Terminal Storage Tanks	218	154	-
Blending & Misc. Equipment	304	223	-
Mobile Facilities			
Rail Cars	784	552	-
Barges	47	33	-
Tank Trucks	90	63	-
Total Capital Costs (Million $)	2,036	1,392	NA
Total Capital Costs (cents per gallon of cellulosic distillate fuel)	2 2		NA

We estimate that cellulosic distillate freight costs would be 13 cents per gallon on a national average basis under both the primary and low-ethanol scenarios. This estimate is based on the application to cellulosic distillate freight costs of an analysis conducted for EPA by Oak Ridge National Laboratory (ORNL) of ethanol freight costs.[332] The underlying premise is that both ethanol and cellulosic distillate fuel would be handled by the same types of distribution facilities on the journey to petroleum terminals.[333] Summing the freight and capital costs results in an estimated 15 cents per gallon in total distribution costs for both the primary and low-ethanol scenarios under both reference cases.

The ethanol and cellulosic distillate distribution cost estimates are based on the projections of the location of biofuel production facilities and end use areas contained in the NPRM. The extent to which new biofuel production facilities are more dispersed than projected in the NPRM, distribution costs for ethanol from new production facilities and for all cellulosic distillate facilities may tend be lower than those projected by this analysis as the fuel has more opportunity to be used locally. This would potentially be a greater benefit in lowering cellulosic distillate distribution costs than overall ethanol distribution costs given the large number of ethanol production facilities currently located in the Midwest. Cellulosic distillate costs should also tend to be lower than those for ethanol because cellulosic distillate fuel blends are compatible with existing petroleum distribution equipment, whereas there are special considerations associated with the distribution of ethanol. The most notable of these

[332] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints", prepared for EPA by Oak Ridge National Laboratory, March 2009. See Section 4.2 of the RIA for additional discussion of the estimation of cellulosic distillate freight costs.
[333] The same unit train and manifest rail receipt facilities would be used to handle shipments of both fuels.

considerations is the need for special fuel retail equipment for E85 (as evidenced in Table VII.B.1-1). Thus, the cellulosic distillate distribution costs estimated here are likely to be conservative.

3. Biodiesel Distribution Costs

Table VII.B.3-1 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional biodiesel that we project will be used under RFS2 by 2022 relative to the RFS reference case of 300 MGY by 2022.[334] The total capital costs are estimated at $1.2 billion which equates to approximately 10 cents per gallon of additional biodiesel volume.[335]

Table VII.B.3-1
Estimated Biodiesel Distribution Infrastructure Capital Costs
Under the RFS1 Reference Case

Million	$
Fixed Facilities	
Petroleum Terminals	
Storage Tanks	411
Blending & Misc. Equipment	612
Mobile Facilities	
Rail Cars	111
Barges	53
Tank Trucks	25
Total Capital Costs (Million $)	1,212
Total Capital Costs (cents per gallon of biodiesel)	10

Table VII.B.3-2 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional biodiesel that we project will be used under RFS2 by 2022 relative to the AEO reference case of 380 MGY. The total capital costs are estimated at $1.1 billion which equates to approximately 10 cents per gallon of additional biodiesel volume.

334 We project that by 2022 300 MGY of biodiesel would be used under the RFS1 reference case, 380 MGY of biodiesel would be used under the RFS reference case and that a total of 1.67 BGY of biodiesel would be used under the EISA. Biodiesel use is projected to be the same under all three of analysis scenarios.

335 These capital costs will be incurred incrementally through 2022 as biodiesel volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

Table VII.B.3-2
Estimated Biodiesel Distribution Infrastructure Capital Costs
Under the AEO Reference Case

Million	$
Fixed Facilities	
Petroleum Terminals	
Storage Tanks	387
Blending & Misc. Equipment	576
Mobile Facilities	
Rail Cars	105
Barges	50
Tank Trucks	24
Total Capital Costs (Million $)	1,141
Total Capital Costs (cents per gallon of biodiesel)	10

We estimate that biodiesel freight costs would be 10 cents per gallon on a national average basis. State biodiesel use requirements and biodiesel production locations were taken into account in formulating this estimate.[336] The biodiesel blend ratio was estimated to vary between 2 and 5%. Adding the estimated freight costs to the amortized capital costs results in an estimate of total biodiesel distribution costs of 20 cents per gallon under both the RFS1 and AEO reference cases.

C. Reduced U.S. Refining Demand

As renewable and alternative fuel use increases, the volume of petroleum-based products, such has gasoline and diesel fuel, would decrease. This reduction in finished refinery petroleum products results in reduced refinery industry costs. The reduced costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel. There is also a reduction in capital costs as investment in new refinery capacity is displaced by investments in renewable and alternative fuels capacity.

Although we conducted refinery modeling for estimating the cost of blending ethanol (see Section VII.B), we did not rely on the refinery model results for estimating the volume of displaced petroleum as other economic factors also come into play. Instead we conducted an energy balance around the increased use of renewable fuels, estimating the energy-equivalent volume of gasoline or diesel fuel displaced. This allowed us to more easily apply our best estimates for how much of the petroleum would displace imports of finished products versus crude oil for our energy security analysis which is discussed in Section VIII.B of this preamble.

As part of this petroleum displacement analysis, we accounted for the change in petroleum demanded by upstream processes related to additional production of the renewable fuels as well as reduced production of petroleum fuels. For example, growing corn used for

[336] See Section 4.2 of the RIA for a discussion of our derivation of biodiesel distribution costs.

ethanol production requires the use of diesel fuel in tractors, which reduces the volume of petroleum displaced by the ethanol. Similarly, the refining of crude oil uses by-product hydrocarbons for heating within the refinery, therefore the overall effect of reduced gasoline and diesel fuel consumption is actually greater because of the additional upstream effect. We used the lifecycle petroleum demand estimates provided for in the GREET model to account for the upstream consumption of petroleum for each of the renewable and alternative fuels, as well as for gasoline and diesel fuel. Although there may be some renewable fuel used for upstream energy, we assumed that this entire volume is petroleum because the volume of renewable and alternative fuels is fixed by the RFS2 standard.

We assumed that a portion of the gasoline displaced by ethanol would have been produced from domestic refineries causing reduced demand from US refineries, while the rest of the additional ethanol displaces imported gasoline or gasoline blendstocks which does not affect domestic refining sector costs. To estimate the portion of new ethanol which displaces US refinery production we relied on some Markal refinery modeling conducted for us by DOE. The Markal refinery model models all the refinery sectors of the world and thus can do a fair job estimating how renewable fuels would impact imports of finished gasoline and gasoline blendstocks. The Markal refinery model estimated that 2/3rds of a reduction in petroleum gasoline demand would be met by a reduction in imported gasoline or gasoline blendstocks, while the other $1/3^{rd}$ would be met by reduced refining production by the US refining sector. In the case of biodiesel and renewable diesel, all of it is presumed to offset domestic diesel fuel production. For ethanol, biodiesel and renewable diesel, the amount of petroleum fuel displaced is estimated based on the relative energy contents of the renewable fuels to the fuels which they are displacing. The savings due to lower imported gasoline and diesel fuel is accounted for in the energy security analysis contained in Section VIII.B.

For estimating the U.S. refinery industry cost reductions, we multiplied the estimated volume of domestic gasoline and diesel fuel displaced by the projected wholesale price for each of these fuels in 2022, which are $3.42 per gallon for gasoline, and $3.83 per gallon for diesel fuel. For the volume of petroleum displaced upstream, we valued it using the wholesale diesel fuel price. Table VII.C-1 shows the net volumetric impact on the petroleum portion of gasoline and diesel fuel demand, as well as the reduced refining industry costs for 2022.

Table VII.C-1
Changes in U.S. Refinery Industry Volumes and Costs for Increased Renewable Fuel Volumes in 2022 Relative to the AEO 2007 Reference Case
(2007 dollars)

		Low Ethanol Case		Primary Case (mid-ethanol case)		High Ethanol Case	
		Bil Gals	Bil $	Bil Gals	Bil $	Bil Gals	Bil $
Upstream	Petroleum	0.34	1.3	0.34 1.3	0.33 1.3		
End Use	Gasoline	-0.9	-3.1	-2.0	-6.8	-4.4	-15.0
	Diesel Fuel	-10.1	-38.7	-7.5	-28.7	-1.3	-5.0
	Total	-10.7	-40.5	-9.2	-34.2	-5.4	-18.7

For the primary control case relative to the AEO 2007 reference case, this analysis estimates that the increased volumes of renewable fuel would reduce the gasoline and diesel fuel production volume of US refineries by 9.2 billion gallons in 2022, which would reduce their raw material purchases and production costs by $34 billion dollars. Accounting for all the petroleum displaced (domestic and foreign), the increased volumes of renewable fuel caused by the RFS 2 fuels program are estimated to reduce gasoline and diesel fuel demand by 13.2 billion gallons.

D. Total Estimated Cost Impacts

The previous sections of this chapter presented estimates of the cost of producing and distributing corn-based and cellulosic-based ethanol, cellulosic diesel fuel, imported ethanol, biodiesel, and renewable diesel. In this section, we briefly summarize the methodology used and the results of our analysis to estimate the cost and other implications for increased use of renewable fuels to displace gasoline and diesel fuel. An important aspect of this analysis is refinery modeling which primarily was used to estimate the costs of blending ethanol into gasoline, as well as the overall refinery industry impacts of the fuel program. A detailed discussion of how the renewable fuel volumes affect refinery gasoline production volumes and cost is contained in Chapter 4 of the RIA.

1. Refinery Modeling Methodology

The refinery modeling was conducted in three distinct steps. The first step involved the establishment of a 2004 base case which calibrated the refinery model against 2004 volumes, gasoline quality, and refinery capital in place. The EPA and ASTM fuel quality constraints in effect by 2004 are imposed on the products.

For the second step, we established two year 2022 future year reference cases which based their energy demand off of the 2009Annual Energy Outlook (AEO). One of the reference cases assumes business-as-usual demand growth from the AEO 2007 reference case discussed in Section IV.A.1. The other utilized the RFS1 reference case. The refinery modeling results are based on $116 per barrel crude oil prices which are the 2022 projected prices by EIA in its 2009 AEO. We also modeled the implementation of several new environmental programs that will have required changes in fuel quality by 2022, including the 30 part per million (ppm) average gasoline sulfur standard, the 15 ppm cap standards on highway and nonroad diesel fuel, the Mobile Source Air Toxics (MSAT) 0.62 volume percent benzene standard. We also modeled the implementation of EPAct of 2005, which by rescinding the reformulated gasoline oxygenate standard, resulted in the discontinued use of MTBE, and a large increase in the amount of ethanol blended into reformulated gasoline. We also modeled the EISA Energy Bill corporate average fuel economy (café) standards in the reference case because it will be phasing-in, and affect the phase-in of the RFS2.

The third step, or the control cases, involved the modeling of three different possible renewable fuels volumes. The three different volumes were designed to capture the additional use of corn ethanol and biodiesel and a range of cellulosic ethanol and cellulosic diesel fuel volumes. The volumes that we assessed in our analysis are summarized in Section IV.A above

The price of ethanol and E85 used in the refinery modeling is a critical determinant of the overall economics of using ethanol. Ethanol was priced initially based on the historical average price spread between regular grade conventional gasoline and ethanol, but then adjusted post-modeling to reflect the projected production cost for both corn and cellulosic-based ethanol. The refinery modeling assumed that all ethanol added to gasoline for E10 is match-blended for octane by refiners in the reference and control cases. For the control case, E85 was assumed to be priced lower than gasoline to reflect its lower energy content, longer refueling time and lower availability (see Chapter 4 of the RIA for a detailed discussion for how we projected E85 prices). For the refinery modeling, E85 was assumed to be blended with gasoline blendstock designed for blending with E10, and with butane to bring the RVP of E85 up to that allowed by ASTM International standards for E85. Thus, unlike current practices today where E85 is blended at 85% in the summer and E70 in the winter, we assumed that E85 is blended at 85% year-round. As E85 specifications are still under consideration by ASTM, this assumption may differ from future procedures. E85 use in any one market is limited to levels which we estimated would reflect the ability of FFV vehicles in the area to consume the E85 volume. Our costs also include the incremental costs of producing flexible fuel vehicles (FFVs) over that of conventionally fueled vehicles.

The refinery model was provided some flexibility and also was constrained with respect to the applicable gasoline volatility standards for blending up E10. The refinery model allowed conventional gasoline and most low RVP control programs to increase by 1.0 pounds per square inch (psi) in Reid Vapor Pressure (RVP) waiver during the summer. However, wintertime conventional gasoline was assumed to comply with the wintertime ASTM RVP and Volume/Liquid (V/L) standards.

The costs for producing, distributing and using biodiesel and renewable diesel are accounted for outside the refinery modeling. Their production and distribution costs are estimated first, compared to the costs of producing diesel fuel, and then are added to the costs estimated by the refinery cost model for blending the ethanol.

2. Overall Impact on Fuel Cost

Utilizing the refinery modeling output conducted for today's final rule, we calculated the costs for each control case, which represented the three different renewable fuels scenarios in 2022, relative to the AEO 2007 and RFS1 reference cases. The costs are reported separately for blending ethanol into gasoline, as E10 and E85, and for blending cellulosic diesel fuel, biodiesel and renewable diesel into petroleum-based diesel fuel. These costs do not include the biofuel consumption tax subsidies. The costs are based on 2007 dollars and the capital costs are amortized at seven percent return on investment (ROI) before taxes.

Tables VII.D.2-1 and VII.D.2-2 summarize the costs for each of the three control cases, including the aggregated total for all the fuel changes and the per-gallon costs, relative to the AEO 2007 and RFS1 reference cases, respectively. This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of renewable and alternative fuels. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. These cost estimates do not account for the various tax subsidies. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline and diesel fuel projected to be consumed in 2022. These costs are only for the incremental renewable fuel volumes beyond the volumes modeled in the two reference cases.

Table VII.D.2-1
Estimated Fuel Costs of Increased Volumes of Renewable Fuel in 2022
Incremental to the AEO2007 Reference Case
(2007 dollars, 7% ROI before taxes)

		Low Ethanol Case	Primary Case (mid-ethanol case)	High Ethanol Case
Gasoline Impacts	$billion/yr	-0.67	-3.31	-5.90
	c/gal	-0.48	-2.35	-4.08
Diesel Fuel Impacts	$billion/yr	-11.7	-8.5	-1.27
	c/gal	-16.4	-12.1	-1.79
Total Impact	$billion/yr	-12.4	-11.8	-7.17

Incremental to the AEO 2007 reference case, our analysis shows that for the low ethanol case which models mostly cellulosic diesel instead of cellulosic ethanol, the gasoline and diesel fuel costs are projected to decrease by $0.7 billion and $11.70 billion, respectively, for a total savings of $12.4 billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 0.5 and 16.4 cents per gallon, respectively.

For our primary case which models a mix of cellulosic diesel fuel and cellulosic ethanol, the gasoline and diesel fuel costs are projected to decrease by $3.3 billion and $8.5 billion, respectively, for a total savings of $11.8 billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 2.4 and 12.1 cents per gallon, respectively.

For the high ethanol case where the cellulosic biofuel is cellulosic ethanol (as in the proposal), the gasoline and diesel fuel costs are projected to decrease by $5.9 billion and $1.3 billion, respectively, for a total savings of $7.2 billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 4.1 and 1.8 cents per gallon, respectively.

Crude oil prices have been very volatile over the last several years which raises uncertainty about future crude oil prices. Because our cost model was created to be able to assess the cost of the program at a higher crude oil price, we can also assess the cost at other crude oil prices. As a sensitivity, we varied crude oil prices in our model to find the break-even (no cost) point of the RFS2 program. Using our cost model we estimate that, for the primary control case relative to the AEO 2007 reference case, the RFS2 program (total of gasoline and diesel fuel costs) would break-even at a 2022 crude oil price of $88 per barrel. Thus, in 2022 if crude oil is priced lower than $88 per barrel, the RFS2 program would cost money; if crude oil is priced higher than $88 per barrel, the RFS2 program would result in a cost savings.

Table VII.D.2-2
Estimated Fuel Costs of Increased Volumes of Renewable Fuel in 2022
Incremental to the RFS1 Reference Case
(2007 dollars, 7% ROI before taxes)

		Low Ethanol Case	Primary Case (mid-ethanol case)	High Ethanol Case
Gasoline Impacts	$billion/yr	-3.12	-5.63	-7.79
	c/gal	-2.24	-4.00	-5.38
Diesel Fuel Impacts	$billion/yr	-11.7	-8.6	-1.35
	c/gal	-16.5	-12.1	-1.90
Total Impact	$billion/yr	-14.8	-14.2	-9.14

Incremental to the RFS1 reference case, our analysis shows that for the low ethanol case which models mostly cellulosic diesel instead of cellulosic ethanol, the gasoline and diesel fuel costs are projected to decrease by $3.1 billion and $11.70 billion, respectively, for a total savings of $14.8 billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 2.4 and 16.5 cents per gallon, respectively.

For our primary case which models a mix of cellulosic diesel fuel and cellulosic ethanol, the gasoline and diesel fuel costs are projected to decrease by $5.6 billion and $8.6 billion, respectively, for a total savings of $14.2.billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 4.0 and 12.1 cents per gallon, respectively.

For the high ethanol case where the cellulosic biofuel is cellulosic ethanol (as in the proposal), the gasoline and diesel fuel costs are projected to decrease by $7.8 billion and $1.4 billion, respectively, for a total savings of $9.1 billion. Expressed as per-gallon costs, these fuel changes would decrease the cost of producing gasoline and diesel fuel by 5.4 and 1.9 cents per gallon, respectively.

Both the gasoline and diesel fuel costs are negative because of the relatively high crude oil prices estimated by EIA for the year 2022. Given the higher projected crude oil prices and these savings, it is difficult to quantify how much of the increase in renewable fuels and the associated savings is due to the RFS 2 program versus what would have happened regardless in the marketplace. However, even with the high crude oil prices as projected by EIA, some or perhaps even most of the investments in these emerging renewable fuels technologies may not occur without the RFS 2 program in place. The reason for this is that investors are hesitant to invest in emerging technologies when the threat remains for a drop in the price of crude oil leaving their investment dollars stranded. The RFS2 program provides certainty for investors to invest in renewable fuel technologies.

There are two important reasons why the diesel fuel costs are more negative than the gasoline costs when comparing the low ethanol case (high cellulosic diesel case) to the high ethanol case: 1) cellulosic ethanol costs include the costs for fuel flexible vehicles, while vehicles using cellulosic diesel fuel are not expected to require any vehicle modifications, hence there is no additional estimated cost, 2) the crude oil price adjustment based on crude oil and finished gasoline and diesel fuel price data from 2002 to 2008 increases the estimated production cost for petroleum diesel fuel more so than for gasoline – therefore cellulosic diesel shows a greater cost savings. If the diesel fuel prices do not increase more than gasoline prices with higher crude oil prices, then the significantly higher savings for renewable diesel fuel over that for renewable ethanol would be less than that modeled here.

The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. Conversely, as these renewable and alternative fuels are being produced, they supplant gasoline and diesel fuel demand which results in less new investments in refineries compared to business-as-usual. In Table VII.D.2-3, we list the total incremental capital investments that we project would be made for this RFS2 rulemaking incremental to the RFS1 reference case (refer to Chapter 4 of the RIA for more detail).

Table VII.D.2-3
Total Projected U.S. Capital Investments to Meet the Increased Volumes of Renewable Fuel (incremental to the AEO 2007 reference case, billion dollars)

Cost Type	Plant Type	Low Ethanol Case	Primary Case (mid-ethanol case)	High Ethanol Case
Production Costs	Corn Ethanol	3.9	3.9	3.9
	Cellulosic Ethanol	0	14.3	48.3
	Cellulosic Diesel [a] 96.5		68.0	0
	Renewable Diesel and Algae	1.1 1.1		1.1
Distribution Costs	All Ethanol	5.6	8.2	11.9
	Cellulosic and Renewable Diesel Fuel	2.0 1.4		-
	Biodiesel 1.2		1.2	1.2
FFV	Costs	0.8	1.8	6.1
Refining		-10.7	-9.4	-4.1
Total Capital Investments		110.4	90.5	68.4

a Cellulosic diesel fuel is assumed to be produced by BTL plants which is a very capital intensive technology. If some or even most of this volume comes from other cellulosic diesel fuel technologies which are less capital intensive, the capital costs attributed to cellulosic diesel would be much lower.

Table VII.D.2-3 shows that the total U.S. capital investments attributed to this program ranges from $71 to $111 billion in 2022 for the high ethanol to low ethanol cases. The capital investments made for renewable fuels technologies are much more than the decrease in refining industry capital investments because 1) a large part of the decrease in petroleum gasoline supply was from reduced imports, 2) renewable fuels technologies are more capital intensive per gallon of fuel produced than incremental increases in gasoline and diesel fuel production at refineries, and 3) ethanol and biodiesel require considerable distribution and retail infrastructure investments.

VIII. Economic Impacts and Benefits

A. Agricultural and Forestry Impacts

EPA used two principal tools to model the potential domestic and international impacts of the RFS2 on the U.S. and global agricultural sectors. The Forest and Agricultural Sector Optimization Model (FASOM), developed by Professor Bruce McCarl of Texas A&M University and others, provides detailed information on the domestic agricultural and forestry sectors, as well as greenhouse gas impacts of renewable fuels. The Food and Agricultural Policy Research Institute (FAPRI) at Iowa State University and the University of Missouri-Columbia maintains a number of econometric models that are capable of providing detailed information on impacts on international agricultural markets from the wider use of renewable fuels in the U.S. EPA worked directly with the Center for Agriculture and Rural Development (CARD) at Iowa State University to implement the FAPRI model to analyze the impacts of the RFS2 on the global agriculture sector. Thus, this model will henceforth be referred to as the FAPRI-CARD model.

FASOM is a long-term economic model of the U.S. agriculture and forestry sectors that attempts to maximize total revenues for producers while meeting the demands of consumers. FASOM can be utilized to estimate which crops, livestock, forest stands, and processed agricultural and forestry products would be produced in the U.S. given RFS2 biofuel requirements. In each model simulation, crops compete for price sensitive inputs such as land and labor at the regional level and the cost of these and other inputs are used to determine the price and level of production of primary commodities (e.g., field crops, livestock, and biofuel products). FASOM also estimates prices using costs associated with the processing of primary commodities into secondary products (e.g., converting livestock to meat and dairy, crushing soybeans to soybean meal and oil, etc.). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends (i.e., five to ten years).

There are a few notable changes that have been made to both the FASOM and FAPRI-CARD models, as well as to some of the underlying assumptions used in the agro-economic analysis since the release of the proposed rulemaking analysis. These changes were made as a result of further research and consultation with experts, as well as in response to comments received during the public comment period following the release of the proposed rulemaking. In regards to the FASOM model, the first major change made to the model is the inclusion of the full interaction between the forestry and agriculture sectors, as discussed in the NPRM and supported by comments received. For the proposed rulemaking, the FASOM model was only capable of modeling the changes in the agriculture sector alone. In terms of land use, the only land use that could be examined was cropland and pasture use. With the incorporation of a forestry sector that dynamically interacts with the agriculture, we are able to examine how crop and forest acres compete for land in response to changes in policy. Also, similar to the agriculture sector, the forestry sector has its own set of forestry products, including logging and milling residues that are available for the production of cellulosic ethanol.

The second major change to the FASOM model is the addition of a full accounting of major land types in the U.S., including cropland, cropland pasture, forestland, forest pasture, rangeland, acres enrolled in the Conservation Reserve Program (CRP), and developed land. These changes address comments raised by peer reviewers and the general public that we should more explicitly link the interaction between livestock, pasture land, cropland, and forest land, as well as have a detailed accounting of acres in the U.S. across different land uses. Cropland is actively managed cropland, used for both traditional crops (e.g., corn and soybeans) and dedicated energy crops (e.g., switchgrass). Cropland pasture is managed pasture land used for livestock production, but which can also be converted to cropland production. Forestland contains a number of sub-categories, tracking the number of acres both newly and continually harvested (reforested), the number of acres harvested and converted to other land uses (afforested), as well as the amount of forest acres on public land. Forest pasture is unmanaged pasture land with varying amounts of tree cover that can be used for livestock production. A portion of this land may be used for timber harvest. Rangeland is unmanaged land that can be used for livestock grazing production. While the amount of rangeland idled or used for production may vary, rangeland may not be used for any other purpose than for cattle grazing.

A third major change in the FASOM model is the adoption of updated cellulosic ethanol conversion rates. We updated the cellulosic ethanol conversion rates based on new data provided by the National Renewable Energy Laboratory (NREL). The new analysis by NREL simplified and updated the conversion yields of the different types of feedstocks. As a result of these changes, the gallons per ton yields for switchgrass and several other feedstocks increased from the values used in the proposal, while the yields for corn residue and several other feedstocks decreased slightly from the NPRM values. In addition, we also updated our feedstock production yields based on new work conducted by the Pacific Northwest National Laboratory (PNNL).[337] This analysis increased the tons per acre yields for several dedicated energy crops. These changes increased the amount of cellulosic ethanol projected to come from energy crops. Additional details on the FASOM model changes can be found in Chapter 5 of the RIA.

The FAPRI-CARD models are econometric models covering many agricultural commodities. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. They are based on historical data analysis, current academic research, and a reliance on accepted economic, agronomic, and biological relationships in agricultural production and markets. The international modeling system includes international grains, oilseeds, ethanol, sugar, and livestock models. In general, for each commodity sector, the economic relationship that supply equals demand is maintained by determining a market-

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[337] Thomson, A.M., R.C. Izarrualde, T.O. West, D.J. Parrish, D.D. Tyler, and J.R. Williams. 2009. *Simulating Potential Switchgrass Production in the United States*. PNNL-19072. College Park, MD: Pacific Northwest National Laboratory.

clearing price for the commodity. In countries where domestic prices are not solved endogenously, these prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector can be linked, changes in one commodity sector will impact other sectors. Elasticity values for supply and demand responses are based on econometric analysis and on consensus estimates.

As one of the largest and fastest developing countries in the world, a major producer and exporter of sugar ethanol, and in possession of one of the world's largest carbon sinks, the Amazon, Brazil is acknowledged to be an important part of our analysis in terms of indirect land use change. For the proposal's analysis, the FAPRI-CARD model analyzed Brazil at a national level as any other non-US nation in the model, covering only crop area and commodity prices. Comments and feedback received indicated the importance of analyzing Brazil at a regional level, given its diverse natural lands across the country, and to also closely examine livestock production in terms of land use.

In response to these comments, the FAPRI-CARD model now includes an integrated Brazil module that provides additional detail on agricultural land use in Brazil for six geographic regions. The new Brazil module explicitly models the competition between cropland and pastureland used for livestock production in each region. In addition, the Brazil module allows for region-specific agriculture practices such as double cropping and livestock intensification in response to higher commodity prices. The addition of the Brazil module allows for a more refined analysis of land use change and economic impacts in Brazil than what was able to be done for the proposal's analysis.

Another topic that we received comments on was in regards to price-induced yields. Namely that with an increase in price for a particular crop, seed producers and/or farmers have a greater incentive to increase yields for that particular crop in order to maximize revenue. In the analysis for proposal, the FAPRI-CARD model did not include impacts of commodity price changes on yields. For the final rulemaking, the FAPRI-CARD model now includes feedback from changes in commodity prices on yields. The elasticities for these responses are based on an econometric analysis of historical data on yield and price changes for various commodities. Additional details on the FAPRI-CARD modeling updates can be found in Chapter 5 of the RIA.

In the NPRM, we specifically requested comments on our assumptions regarding distiller grain with solubles (DGS) replacement rates. For the proposal, we assumed that one pound of DGS replaced one pound of total of corn and soybean meal for all fed animals. We received numerous comments on this assumption. Many commenters suggested that we adopt the replacement rates included in the recent research by Argonne National Laboratory (ANL) and others.[338] The ANL study found that one pound of DGS can be used to replace 1.196 pounds total of corn and soybean meal for various fed animals due to the higher nutritional content of DGS per pound compared to corn and soybean meal. For the final rulemaking analysis, these replacement rates are

[338] Salil Arora, May Wu, and Michael Wang, "Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis," September 2008. See http://www.transportation.anl.gov/pdfs/AF/527.pdf

incorporated in both the FASOM and FAPRI-CARD models, and are treated as a maximum replacement rate possibility that is fully phased in by 2015. In addition, the maximum inclusion rates for DGS in an animal's diet have also been incorporated into the models. Given these parameters, each agriculture sector model determines the total quantity of DGS used in feed based on relative prices for competing feed sources.

In addition, both FASOM and FAPRI-CARD now explicitly model corn oil from the dry mill ethanol extraction process as a new source of biodiesel. Based on engineering research (refer to Section VII.A) regarding expected technological adoption, it is estimated that 70% of dry mill ethanol plants will withdraw corn oil via extraction (from DGS), resulting in corn oil that is non-food grade and can only be used as a biodiesel source; 20% will withdraw corn oil via fractionation (prior to the creation of DGS), resulting in corn oil that is food-grade; and 10% will do neither extraction or fractionation. Based on this research, both the FASOM and FAPRI-CARD models are estimating that approximately 681 million gallons of biodiesel can be produced from non-food grade corn oil from extraction by 2022 in the Control Case. Additional information regarding these changes to the FASOM and FAPRI-CARD models can be found in RIA Chapter 5.

1. <u>Biofuel Volumes Modeled</u>

For the agricultural sector analysis using the FASOM and FAPRI-CARD models of the RFS2 biofuel volumes, we assumed 15 billion gallons (Bgal) of corn ethanol would be produced for use as transportation fuel by 2022, an increase of 2.7 Bgal from the Reference Case. Also, we modeled 1.7 Bgal of biodiesel use as fuel in 2022, an increase of 1.3 Bgal from the Reference Case. In addition, we modeled an increase of 16 Bgal of cellulosic ethanol in 2022. In FASOM, this volume consists of 4.9 billion gallons of cellulosic ethanol coming from corn residue in 2022, 7.9 billion gallons from switchgrass, 0.6 billion gallons from sugarcane bagasse, and 0.1 billion gallons from forestry residues.

Given the nature of the models, there are some limitations on what each model may explicitly model as a biofuel feedstock source. For example, since FASOM is a domestic agricultural sector model it cannot be utilized to examine the impacts of the wider use of biofuel imports into the U.S. Similarly, the FAPRI-CARD model does not explicitly model the forestry sector in the U.S. and therefore does not include biofuels produced from the U.S. forestry sector. Also, neither of the two models used for this analysis—FASOM or FAPRI-CARD—include biofuels derived from domestic municipal solid waste. Thus, for the RFS2 agricultural sector analysis, these biofuel sources are analyzed outside of the agricultural sector models.

All of the results presented in this section are relative to the AEO 2007 Reference Case renewable fuel volumes, which include 12.3 Bgal of grain-based ethanol, 0.4 Bgal of biodiesel, and 0.3 Bgal of cellulosic ethanol in 2022. The domestic figures are provided by FASOM, and all of the international numbers are provided by FAPRI-

CARD. The detailed FASOM results, detailed FAPRI-CARD results, and additional sensitivity analyses are described in more detail in the RIA.

Table VIII.A.1-1
Ethanol Source Volumes Modeled in 2022
(Billions of Gallons)

Ethanol Source	AEO 2007 Reference Case	Control Case	Change
Corn Ethanol	12.3	15.0	2.7
Corn Residue Cellulosic Ethanol *	0	4.9	4.9
Sugarcane Bagasse Cellulosic Ethanol *	0.2	0.6	0.4
Switchgrass Cellulosic Ethanol *	0	7.9	7.9
Forestry Residue Cellulosic Ethanol *	0	0.1	0.1
Net Imports of Sugarcane Ethanol **	0.6	2.2	1.6
Other Ethanol ***	0.1	2.6	2.5

* Cellulosic Ethanol feedstocks are not explicitly modeled in FAPRI-CARD
** Net Imports of Sugarcane Ethanol is not explicitly modeled in FASOM
*** Includes MSW, which is not explicitly modeled by either FASOM or FAPRI-CARD.

Table VIII.A.1-2
Biodiesel Source Volumes Modeled in 2022
(Millions of Gallons)

Biodiesel Source	AEO 2007 Reference Case	Control Case	Change
Soybean Oil	119.9	659.4	539.5
Corn Oil (Dry Mill Extraction)	0.4	681.3	680.8
Animal Fats	93.9	126.9	33.0
Yellow Grease	170.9	253.1	82.3

2. Commodity Price Changes

For the scenario modeled, FASOM predicts that in 2022 U.S. corn prices would increase by $0.27 per bushel (8.2%) above the Reference Case price of $3.32 per bushel. By 2022, U.S. soybean prices would increase by $1.02 per bushel (10.3%) above the Reference Case price of $9.85 per bushel. In 2022, U.S. soybean oil prices would increase $183.32 per ton (37.9%) above the Reference Case price of $483.10 per ton. Hardwood lumber prices are unaffected by the increase in biofuel demand, however softwood lumber prices increase by $0.46 per board foot (0.1%) in 2022 to $386 per board foot. Additional price impacts are included in Section 5 of the RIA.

Table VIII.A.2-1
Change in U.S. Commodity Prices
from the AEO 2007 Reference Case (2007$)

Commodity Change		% Change
Corn $0.27/bushel		8.2%
Soybeans $1.02/bushel		10.3%

Soybean Oil	$183.32/ton	37.9%
Hardwood Lumber	$0.00/board foot	0%
Softwood Lumber	$0.46/board foot	0.1%

By 2022, the price of switchgrass would increase by $20.12 per wet ton to the Control Case price of $40.85 per wet ton. Additionally, the farm gate feedstock price of corn residue would increase by $29.48 per wet ton to the Control Case price of $34.49 per wet ton. The price of sugarcane bagasse would increase $23.27 to the Control Case price of $29.70 per wet ton by 2022. Softwood logging residue prices would increase $8.99 per wet ton to $18.37 per wet ton in the Control Case in 2022. Similarly, the price of hardwood logging residues would increase by $17.85 per wet ton to the Control Case price of $23.22 per wet ton in 2022. These prices do not include the storage, handling, or delivery costs, which would result in a delivered price to the ethanol facility of at least twice the farm gate cost, depending on the region.

Table VIII.A.2-2
Change in U.S. Cellulosic Feedstock Prices
from the AEO 2007 Reference Case (2007$)

Commodity	Control Case Price	Change
Switchgrass	$40.85/wet ton	$20.12/wet ton
Corn Residue	$34.49/wet ton	$29.48/wet ton
Sugarcane Bagasse	$29.70/wet ton	$23.27/wet ton
Softwood Logging Residue	$18.37/wet ton	$8.99/wet ton
Hardwood Logging Residue	$23.22	$17.85/wet ton

3. Impacts on U.S. Farm Income

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that net U.S. farm income would increase by $13 billion dollars in 2022 (36%), relative to the AEO 2007 Reference Case.

4. Commodity Use Changes

Changes in the consumption patterns of U.S. corn can be seen by the increasing percentage of corn used for ethanol. FASOM estimates the amount of domestically produced corn used for ethanol in 2022 would increase to 40.5%, relative to the 33.2% usage rate under the Reference Case.

The rising price of corn and soybeans in the U.S. would also have a direct impact on how corn is used. Higher domestic corn prices would lead to lower U.S. exports as the world markets shift to other sources of these products or expand the use of substitute grains. FASOM estimates that U.S. corn exports would drop 188 million bushels (-8.2%) to 2.1 billion bushels by 2022. In value terms, U.S. exports of corn would fall by $57 million (-0.8%) to \$7.5 billion in 2022. U.S. exports of soybeans would also decrease due to the increased use of renewable fuels. FASOM estimates that U.S. exports of soybeans would decrease 135 million bushels (-13.6%) to 858 million bushels by 2022. In value terms, U.S. exports of soybeans would decrease by \$453 million (-4.6%) to \$9.3 billion in 2022.

Table VIII.A.4-1
Change in U.S. Exports
from the AEO 2007 Reference Case in 2022

Exports	Change	% Change
Corn in Bushels	-188 million	-8.2 %
Soybeans in Bushels	-135 million	-13.6%
Total Value of Exports	Change	% Change
Corn (2007\$)	- \$57 million	-0.8%
Soybeans (2007\$)	- \$453 million	-4.6%

Lumber production in the U.S. is affected as well, as forestry acres decrease as a result of expanding crop acres (see below). In 2022, hardwood lumber production increases by 0.2%, and softwood production decreases by -0.2%.

Table VIII.A.4-2
Percent Change in U.S. Lumber Production
from the AEO 2007 Reference Case in 2022

Commodity %	Change
Hardwood Lumber	0.2%
Softwood Lumber	-0.2%

Higher U.S. demand for corn for ethanol production would cause a decrease in the use of corn for U.S. livestock feed. Substitutes are available for corn as a feedstock, and this market is price sensitive. Several ethanol processing byproducts could also be used to replace a portion of the corn used as feed, depending on the type of animal. One of the major byproducts of the ethanol production process that can be used as a feed source, and as a substitute for corn and soybean meal, is distiller grains with solubles (DGS). DGS are a by-product of the dry mill ethanol production process. As discussed above, the replacement rates of DGs for corn and soybean meal in the diets of fed animals is higher than what was used in the proposal based on the latest scientific research regarding nutritional content of feed sources. In addition, as discussed above and in Chapter VI, there are new processes for withdrawing corn oil from the dry mill ethanol production process. Therefore, we are now modeling two types of DGS: those that are created during the extraction/fractionation process (fractionated DGS), and those created in plants that do not conduct fractionation or extraction (traditional DGS). In addition, other byproducts that can be used as feed substitutes include gluten meal and gluten feed, which are byproducts of wet milling ethanol production. In 2022, traditional DGS used in feed decreases by 27.5 million tons from the Reference Case to 6.5 million tons in the

Control Case. However, the use of fractionated DGS increases by 32.7 million tons from 20 thousand tons used in the Reference Case in 2022. Gluten meal used in feed decreases by 0.1 million tons (-4.5%) to 2.1 million tons in the Control Case. Gluten feed use increases by 0.3 million tons (6.4%) in 2022 to 4.8 million tons in the Control Case. By 2022, FASOM predicts total ethanol byproducts used in feed would increase by 5.4 million tons (13.2%) to 46.1 million tons, compared to 40.8 million tons under the Reference Case.

Table VIII.A.4-3
Change in Ethanol Byproducts Use
in Feed Relative to the AEO 2007 Reference Case
(Millions of Tons)

Category Control	Case	Change
DGS (Traditional)	6.5	-27.5
DGS (Fractionated)	32.7	32.7
Gluten Meal	2.1	-0.1
Gluten Feed	4.8	0.3
Total Ethanol Byproducts	46.1	5.4

The EISA cellulosic ethanol requirements result in the production of residual agriculture and forestry products, as well as dedicated energy crops. By 2022, FASOM predicts production of 97.4 million tons of switchgrass and 59.9 million tons of corn residue. Sugarcane bagasse for cellulosic ethanol production increases by 6 million tons to 9.6 million tons in 2022 relative to the Reference Case. In addition, FASOM predicts production of 1.7 million tons of forestry residues for cellulosic ethanol production.

5. U.S. Land Use Changes

Higher U.S. corn prices would have a direct impact on the value of U.S. agricultural land. As demand for corn and other farm products increases, the amount of land devoted to cropland production would increase. FASOM estimates an increase of 3.6 million acres (4.6%) in harvested corn acres, relative to 77.9 million acres harvested under the Reference Case by 2022.[339] Most of the new corn acres come from a reduction in existing crop acres, such as rice, wheat, and hay.

Though demand for biodiesel increases, FASOM predicts a fall in U.S. soybean acres harvested. According to the model, harvested soybean acres would decrease by approximately 1.4 million acres (-2.1%), relative to the Reference Case acreage of 68.1 million acres in 2022. Despite the decrease in soybean acres in 2022, soybean oil production would increase by 0.5 million tons (4.7%) by 2022 over the Reference Case. This occurs due to the decrease in soybean exports mentioned above. Additionally, FASOM predicts that soybean oil exports would decrease 1.2 million tons by 2022 (-51%) relative to the Reference Case.

[339] Total U.S. planted corn acres increases to 87.1 million acres from the Reference Case level of 83.5 million acres in 2022.

As the demand for cellulosic ethanol increases, most of the production is derived from switchgrass. By 2022, switchgrass acres from nearly zero acres in the Reference Case, to 12.5 million acres in the Control Case as demand for cellulosic ethanol increases between cases. Similarly, as demand for cellulosic ethanol from bagasse increases, sugarcane acres increase by 0.1 millions acres (20%) to 0.9 million acres by 2022. Although we received comments suggesting that acres enrolled in the Conservation Reserve Program (CRP) may decrease below the 32 million acres assumed in the NPRM, we did not revise this assumption for several reasons. First, the commodity price changes predicted by FASOM are relatively modest and would therefore have a limited impact on the decision to re-enroll in the program. Second, the CRP program is designed to allow for increased payment if land rental rates increase. Therefore, for the reasons outlined in the NPRM, we believe the assumption that CRP acres will not drop below 32 million acres is a plausible future projection.

Table VIII.A.5-1
Change in U.S. Crop Acres Relative to
the AEO 2007 Reference Case in 2022
(millions of acres)

Crop Change		% Change
Corn 3.6		4.6%
Soybeans -1.4		-2.1%
Sugarcane 0.1		20%
Switchgrass 12.5		20,000%

With the increase in biofuel demand that results from the implementation of the RFS2 policy, there is an increase of 3.1 million acres are dedicated towards crop production. This increase in crop acres results in a decrease of -1.9 million pasture acres, an increase of 1.1 million acres of forest pasture, and a decrease of 1.2 million forestry acres.

Table VIII.A.5-2
Change in U.S. Crop Acres Relative to
the AEO 2007 Reference Case in 2022
(millions of acres)

Land Type	Change	% Change
Cropland 3.1		1.0%
Cropland Pasture	-1.9	-5.8%
Forest Pasture	1.1	0.7%
Forestry	-1.2	-0.3%

The additional demand for corn and other crops for biofuel production also results in increased use of fertilizer in the U.S. In 2022, FASOM estimates that U.S. nitrogen fertilizer use would increase 1.5 billion pounds (5.7%) over the Reference Case nitrogen fertilizer use of 26.2 billion pounds. In 2022, U.S. phosphorous fertilizer use would increase by 714 million pounds (12.7%) relative to the Reference Case level of 5.6 billion pounds.

Table VIII.A.5-3
Change in U.S. Fertilizer Use Relative
to the AEO 2007 Reference Case (millions of pounds)

Fertilizer Change		% Change
Nitrogen 1,501		5.7%
Phosphorous 714		12.7%

6. Impact on U.S. Food Prices

Due to higher commodity prices, FASOM estimates that U.S. food costs[340] would increase by roughly $10 per person per year by 2022, relative to the Reference Case.[341] Total effective farm gate food costs would increase by $3.6 billion (0.2%) in 2022.[342] To put these changes in perspective, average U.S. per capita food expenditures in 2007 were $3,778 or approximately 10% of personal disposable income. The total amount spent on food in the U.S. in 2007 was $1.14 trillion dollars.[343]

7. International Impacts

Changes in the U.S. agriculture economy are likely to have affects in other countries around the world in terms of trade, land use, and the global price and consumption of fuel and food. We utilized the FAPRI-CARD model to assess the impacts of the increased use of renewable fuels in the U.S. on world agricultural markets.

The FAPRI-CARD modeling shows that world corn prices would increase by $0.12 per bushel (3.1%) to $3.88 per bushel in 2022, relative to the Reference Case. The impact on world soybean prices is somewhat smaller, increasing $0.08 per bushel (0.8%) to $9.63 per bushel in 2022.

[340] FASOM does not calculate changes in price to the consumer directly. The proxy for aggregate food price change is an indexed value of all food prices at the farm gate. It should be noted, however, that according to USDA, approximately 80% of consumer food expenditures are a result of handling after it leaves the farm (e.g., processing, packaging, storage, marketing, and distribution). These costs consist of a complex set of variables, and do not necessarily change in proportion to an increase in farm gate costs. In fact, these intermediate steps can absorb price increases to some extent, suggesting that only a portion of farm gate price changes are typically reflected at the retail level. See http://www.ers.usda.gov/publications/foodreview/septdec00/FRsept00e.pdf.
[341] These estimates are based on U.S. Census population projections of 331 million people in 2017 and 348 million people in 2022. See http://www.census.gov/population/www/projections/summarytables.html
[342] Farm Gate food prices refer to the prices that farmers are paid for their commodities.
[343] See www.ers.usda.gov/Briefing/CPIFoodAndExpenditures/Data/table15.htm.

This increase in international commodity prices has a direct impact on world food consumption.[344] The FAPRI-CARD model indicates that world consumption of corn for food would decrease by 0.6 million metric tons in 2022 relative to the Reference Case. Similarly, the FAPRI-CARD model estimates that world consumption of oil for food (e.g., vegetable oils) decreases by 1.7 million metric tons by 2022. Wheat consumption is not estimated to change substantially in 2022. The model also estimates a small change in world meat consumption, decreasing by -0.1 million metric tons in 2022. When considering all the food uses included in the model, world food consumption decreases by 2.4 million metric tons by 2022 (-0.11%). While FAPRI-CARD provides estimates of changes in world food consumption, estimating effects on global nutrition is beyond the scope of this analysis.

Table VIII.A.7-1
Change in World Food Consumption
Relative to the AEO 2007 Reference Case
(millions of metric tons)

Category 2022	
Corn -0.6	
Wheat 0.0	
Vegetable Oils	-1.7
Meat -0.1	
Total Food	-2.4

Additional information on the U.S. agricultural and forestry sectors, as well as international trade impacts are described in more detail in the RIA (Chapter 5).

B. Energy Security Impacts

Increasing usage of renewable fuels helps to reduce U.S. petroleum imports. A reduction of U.S. petroleum imports reduces both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved U.S. energy security. In this section, we detail an updated methodology for estimating the energy security benefits of reduced U.S. oil imports which explicitly includes biofuels and, based upon this updated approach, we estimate the monetary value of the energy security benefits of the RFS2 required renewable fuel volumes.

1. Implications of Reduced Petroleum Use on U.S. Imports

In 2008, U.S. petroleum import expenditures represented 21% of total U.S. imports of all goods and services.[345] In 2008, the U.S. imported 66% of the petroleum it

[344] The food commodities included in the FAPRI model include corn, wheat, sorghum, barley, soybeans, sugar, peanuts, oils, beef, pork, poultry, and dairy products.
[345] Source: U.S. Bureau of Economic Analysis, U.S. International Transactions Accounts Data, as shown on June 24, 2009.

consumed, and the transportation sector accounted for 70% of total U.S. petroleum consumption. This compares to approximately 37% of petroleum from imports and 55% consumption of petroleum in the transportation sector in 1975.[346] It is clear that petroleum imports have a significant impact on the U.S. economy. Requiring the wider use of renewable fuels in the U.S. is expected to lower U.S. petroleum imports.

For this final rule, EPA estimated the reductions in U.S. petroleum imports using a modified version of the National Energy Modeling System (EPA-NEMS). EPA-NEMS is an energy-economy modeling system of U.S. energy markets through the 2030 time period. EPA-NEMS projects U.S. production, imports, conversion, consumption, and prices of energy; subject to assumptions on world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. For this analysis, the 2009 NEMS model was modified to use the 2007 (pre-EISA) Annual Energy Outlook (AEO) levels of biofuels in the Reference Case. These results were compared to our Control Case, which assumes the renewable fuel volumes required by EISA will be met by 2022. The reductions in U.S. oil imports projected by EPA-NEMS as a result of the RFS2 is approximately 0.9 million barrels per day, which amounts to about $41.5 billion in lower crude oil and refined product import payments in 2022.

2. Energy Security Implications

In order to understand the energy security implications of the increased use of renewable fuels, EPA used the Oil Security Metrics Model [347,348] (OSMM), developed and maintained by Oak Ridge National Laboratory. This model examines the future economic costs of oil imports and oil supply disruptions to the U.S., grouping costs into (1) the higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the "import demand" or "monopsony" costs); and (2) the expected cost of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs). Beginning with Reference projections for the oil and liquid fuel markets from the EIA's 2009 AEO, the OSMM compares costs under those futures with selected cases under differing energy policies and technology mixes. It provides measures of expected costs and risk by probabilistic simulation

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[346] Source: U.S. Department of Energy, Annual Energy Review 2008, Report No. DOE/EIA-0384(2008), Tables 5.1 and 5.13c, June 26, 2009.

[347] The OSMM methods are consistent with the recommended methodologies of the National Resource Council's (NRC's) (2005) Committee on Prospective Benefits of DOE's Energy Efficiency and Fossil Energy R&D Programs. The OSMM defines and implements a method that makes use of the NRC's typology of prospective benefits and methodological framework, satisfies the NRC's criteria for prospective benefits evaluation, and permits measurement of prospective energy security benefits for policies and technologies related to oil. It has been used to estimate the prospective oil security benefits of Department of Energy's Energy Efficiency and Renewable Energy R&D programs, and is also applicable to other strategies and policies aimed at changing the level and composition of U.S. petroleum demand. To evaluate the RFS2, the OSMM was modified to include supplies and demand of biofuels (principally ethanol) as well as petroleum.

[348] Leiby, P.N., *Energy Security Impacts of Renewable Fuel Use Under the RFS2 Rule – Methodology*, Oak Ridge National Laboratory, January 19, 2010

through 2022. Uncertainty is inherent in energy security analysis, and it is explicitly represented for long-run future oil market conditions, disruption events, and key parameters.

An important aspect of the OSMM is that it explicitly addresses the energy security implications of the wider use of biofuels as transportation fuels in the U.S. Increased use of biofuels not only results in changes in the levels of U.S. oil imports and consumption, but also can alter key supply and demand oil elasticities. The elasticities are significant for energy security since they measure the potential for substitution away from oil, in the long and short-run, depending on how oil prices evolve and whether oil supply disruptions occur. Also, the OSMM accounts for the potential of supply disruptions from biofuels. For example, there could be a drought in the U.S. that could cause a reduction in the supply of key agricultural feedstocks (i.e., corn) that are used to make ethanol. To the extent that supply disruptions in feedstocks used to make biofuels are correlated with oil supply disruptions, the energy security benefits of biofuels may be lessened, by substituting one fuel with supply disruptions for another. For this analysis, the energy security implications of the wider use of biofuels in the U.S. are broken down between biofuels produced domestically (e.g., ethanol made from corn/switchgrass, soy-based biodiesel) and imported biofuels (e.g., ethanol made from sugarcane).

For the proposed RFS2 rule, EPA worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In the study entitled "*The Energy Security Benefits of Reduced Oil Use, 2006-2015*," completed in March, 2008, ORNL updated and applied the analytical approach used in the 1997 Report "*Oil Imports: An Assessment of Benefits and Costs*." [349,350] This study is included as part of the record in this rulemaking.[351] This study underwent a Peer Review, sponsored by the Agency.

The prior approach that ORNL has developed estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called the “oil import premium”. With OSMM, ORNL uses a consistent approach, estimating the incremental cost to the U.S. of the increased use of renewable fuels required by EISA, and reporting that cost in dollars per barrel of biofuel. In this case, these increased volumes alter both the U.S. oil import and consumption levels, while introducing a substitute fuel and altering demand responsiveness. As before, OSMM considers the economic cost of importing petroleum into the U.S. The economic cost of importing petroleum into the U.S. was defined as (1) the higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., "monopsony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e.,

[349] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November, 1997.
[350] The 1997 ORNL paper was cited and its results used in DOT/NHTSA’s rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008-2011, March 2006.
[351] Leiby, Paul N. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports," Oak Ridge National Laboratory, ORNL/TM-2007/028, Final Report, 2008.

macroeconomic disruption/adjustment costs). Maintaining a U.S. military presence to help secure stable oil supply from potentially vulnerable regions of the world is also a measure of energy security, but has been excluded from this analysis because its attribution to particular military missions or activities is difficult.

a. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the economic costs of importing petroleum into the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one benefit of decreasing U.S. oil purchases is the potential decrease in the crude oil price paid for all crude oil purchased.

In the case of the RFS2, increasing U.S. demand for biofuels partially offsets the U.S. oil market import cost reduction. The offset is because the RFS2 results in a modest increases in biofuels imported to the U.S. (1.6 billion gallons in 2022), and a modest increase in the world ethanol price (from $1.48/gallon to $1.61/gallon, a $0.13/gallon increase in 2022). Thus, the biofuels that the U.S. had imported would be higher priced, partially offsetting the reduction in U.S. oil import costs. The ORNL estimates this monopsony component of the energy security benefit (oil market and biofuel market impacts combined) is $7.86/barrel of biofuel (2007$) for the year 2022, as shown in Table VIII.B.2-1. Based upon the 90 percent confidence interval, the monopsony portion of the energy security benefit ranges from $5.37 to $10.71/barrel of biofuel in the year 2022.

b. Short-Run Disruption Premium from Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length; the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR) to respond; and the sensitivity of the U.S. economy to sudden price increases. The total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports. Variation in oil consumption levels can change the sensitivity of the economy to oil price shocks, and variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions

A major strength of the OSMM is that it addresses risk-shifting that might occur as the U.S. reduces its dependency on petroleum and increases its use of biofuels, which the other "oil premium model" could not. The prior "oil premium" analysis focused only on the potential for biofuels to reduce U.S. oil imports, and the resulting implications of lower U.S. oil imports for energy security. As the U.S. relies more heavily on biofuels, such as corn-based ethanol, there could be adverse consequences from a supply-disruption perspective associated with, for example, a long-term drought. Alternatively, a supply disruption of petroleum will more likely be caused by geopolitical factors rather than extreme weather conditions. Hence, the causal factors of a supply-disruption from imported petroleum and, alternatively, biofuels, are likely to be unrelated. Thus, diversifying the sources of U.S. transportation fuel is expected to provide energy security benefits. Biofuel supply disruptions are represented based on the historical volatility of yields for biofuel feedstocks or similar crops. The ORNL estimates this macroeconomic/disruption component of the energy security benefit (oil market and biofuel market impacts combined) is $6.56/barrel (2007$) for the year 2022, as shown in Table VIII.B.2-1. Based upon the 90 percent confidence interval, the macroeconomic/disruption component of the energy security benefit ranges from $0.94 to $12.23/barrel of biofuel in the year 2022.

Table VIII.B.2-1
Energy Security Benefits of The Volumes Required by RFS2 in 2022
(2007$ per barrel of biofuel)

Component Estim	ate
Monopsony $7.86	($5.37-$10.71)
Macroeconomic Disruption	$6.56 ($0.94-$12.23)
Total $14.42	($6.31-$22.95)

c. Costs of Existing U.S. Energy Security Policies

Another often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. In the peer review of the energy security analysis that the Agency commissioned, a majority of peer reviewers believed that U.S. military costs should be excluded absence a widely agreed methodology for estimating this component of U.S. energy security. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

Some commenters felt that the Agency should attempt to monetize U.S. military costs and include these costs in the energy security analysis, while other commenters agreed with the Agency that these costs should be excluded. The Agency did not receive any new analysis or methodological approach from commenters which could be used to monetize U.S. military costs in a meaningful or credible manner. Since U.S. military impacts are not factored into the energy security analysis, they are also excluded from the lifecycle GHG analysis.

3. Combining Energy Security and Other Benefits

The literature on the energy security for the last two decades has routinely combined the monopsony and the macroeconomic disruption components when calculating the total value of the energy security premium. However, in the context of using a global value for the Social Cost of Carbon (SCC) the question arises: how should the energy security premium be used when some benefits from the increased use of renewable fuels, such as the benefits of reducing greenhouse gas emissions, are calculated at a global level? Monopsony benefits represent avoided payments by the U.S. to oil producers in foreign countries that result from a decrease in the world oil price as the U.S. decreases its consumption of imported oil (net of increased imported biofuel payments by the U.S.) Although there is clearly a benefit to the U.S. when considered from the domestic perspective, the decrease in price due to decreased demand in the U.S. also represents a loss to other countries. Given the redistributive nature of this effect, do the negative effects on other countries "net out" the positive impacts to the U.S.? If this is the case, then, the monopsony portion of the energy security premium should be excluded from the net benefits calculation. Based on this reasoning, EPA's estimates of net benefits for the increased use of renewable fuels required by EISA exclude the portion of energy security benefits stemming from the U.S. exercising its monopsony power in oil markets. Thus, EPA only includes the macroeconomic disruption/adjustment cost portion of the energy security premium.

However, even when the global value for greenhouse gas reduction benefits is used, a strong argument can be made that the monopsony benefits should be included in net benefits calculation. Maintaining the earth's climate is a global public good and as such requires that a global perspective be taken on the benefits of GHG mitigation by all nations, including the U.S. The global SCC is used in these calculations, not because the global net benefits of the increased use of renewable fuels are being computed (they are not), but rather because in the context of a global public good, the global marginal benefit is the correct benefit against which domestic costs are to be compared. In other words, using the global SCC does not transform the calculation from a domestic (i.e., U.S.) to a global one. Rather, the domestic perspective is maintained while recognizing that the impacts from domestic GHG emissions are truly global in nature.

Energy security, on the other hand, is broadly defined as protecting the U.S. economy against circumstances that threaten significant short- and long-term increases in energy costs. Energy security is inherently a domestic benefit. However, the use of the domestic monopsony benefit is not necessarily in conflict with the use of the global SCC, because the global SCC represents the benefits against which the costs associated with our (i.e., the U.S.'s) domestic mitigation efforts should be judged. In addition, the U.S. values both maintaining the earth's climate and providing for its own energy security. If this reasoning holds, the two benefits—the global benefits of reducing greenhouse gas emissions and the full energy security premium, including the monopsony benefits—should be counted in the net benefits estimates. In the final analysis, the Agency determined that the first argument is more compelling and therefore has determined that using only the macroeconomic disruption component of the energy security benefit is the appropriate metric for this rule.

4. Total Energy Security Benefits

In 2022, total annual energy security benefits are estimated for the difference between the renewable fuel volumes in the Primary Control Case (30.50 billion gallons) and the AEO2007 Reference Case (13.56 billion gallons). Total annual energy security benefits are calculated by multiplying the change in renewable fuel volumes (16.94 billion gallons or 403 million barrels) and the macroeconomic disruption/adjustment portion of the energy security premium ($6.56/barrel of renewable fuels). The estimated total energy security benefit is $2.6 billion (2007$) for the year 2022. The estimated total energy security benefit using the macroeconomic disruption/adjustment portion of the energy security benefit in 2022 ranges from $379 million to $4.9 billion based upon the 90 percent confidence intervals.

C. Benefits of Reducing GHG Emissions

1. Introduction

This section presents estimates of the economic benefits that could be monetized for the reductions in GHG emissions projected to occur through the increased use of renewable fuels required by EISA. The total benefit estimates were calculated by multiplying a marginal dollar value (i.e., cost per ton) of carbon emissions, also referred to as "social cost of carbon" (SCC), by the anticipated level of emissions reductions in tons.

The SCC values underlying the benefits estimates for this rule represent U.S. government-wide interim values for SCC. As discussed below, federal agencies will use these interim values to assess some of the economic benefits of GHG reductions while an interagency workgroup develops SCC values for use in the long-term. The interim values should not be viewed as an expectation about the results of the longer-term process. Although these values were not used in the NPRM, some commenters raised issues with these values and the methodology used to develop them in response to their publication elsewhere. Many of these issues are being examined by the interagency workgroup.

The rest of this Preamble section will provide the basis for the interim SCC values, and the estimates of the total climate-related benefits of the increased use of renewable fuels that follow from these interim values. As discussed below, the interim dollar estimates of the SCC represent a partial accounting of climate change impacts.

In addition to the quantitative account presented in this section, a qualitative appraisal of climate-related impacts is published in Section V of today's rule and in other recent climate change analyses. For example, EPA's Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act and the accompanying Technical Support Document (TSD) presents a summary of impacts and risks of climate change projected in the absence of actions to mitigate GHG emissions.[352] The TSD synthesizes major findings from the best available scientific assessments of the scientific literature that have gone through rigorous and transparent peer review, including the major assessment reports of both the Intergovernmental Panel on Climate Change (IPCC) and the U.S. Climate Change Science Program (CCSP).

2. <u>Derivation of Interim Social Cost of Carbon Values</u>

The "social cost of carbon" (SCC) is intended to be a monetary measure of the incremental damage resulting from carbon dioxide (CO_2) emissions, including (but not limited to) net agricultural productivity loss, human health effects, property damages from sea level rise, and changes in ecosystem services. Any effort to quantify and to monetize the consequences associated with climate change will raise serious questions of science, economics, and ethics. But with full regard for the limits of both quantification and monetization of impacts, the SCC can be used to provide an estimate of the social benefits of reductions in GHG emissions.

For at least three reasons, any particular figure will be contestable. First, scientific and economic knowledge about the impacts of climate change continues to grow. With new and better information about relevant questions, including the cost, burdens, and possibility of adaptation, current estimates will inevitably change over time. Second, some of the likely and potential damages from climate change—for example, the loss of endangered species—are generally not included in current SCC estimates. These omissions may turn out to be significant in the sense that they may mean that the best current estimates are too low. As noted by the IPCC Fourth Assessment Report, "It is *very likely* that globally aggregated figures underestimate the damage costs because they cannot include many non-quantifiable impacts." Third, when economic efficiency criteria, under specific assumptions, are juxtaposed with ethical considerations, the outcome may be controversial. These ethical considerations, including those involving

[352] See Federal Register /Vol.74, No.2398/Wednesday, December 16, 2009/Rules and Regulations at http://frwebgate4.access.gpo.gov/cgi-bin/PDFgate.cgi?WAISdocID=969788398047+0+2+0&WAISaction=retrieve or http://epa.gov/climatechange/endangerment.html

the treatment of future generations, should and will also play a role in judgments about the SCC (see in particular the discussion of the discount rate, below).

To date, SCC estimates presented in recent regulatory documents have varied within and among agencies, including DOT, DOE, and EPA. For example, a regulation proposed by DOT in 2008 assumed a value of $7 per metric tonne CO_2[353] (2006$) for 2011 emission reductions (with a range of $0-14 for sensitivity analysis). One of the regulations proposed by DOE in 2009 used a range of $0-$20 (2007$). Both of these ranges were designed to reflect the value of damages to the United States resulting from carbon emissions, or the "domestic" SCC. In the final MY2011 CAFE EIS, DOT used both a domestic SCC value of $2/t-$CO_2$ and a global SCC value of $33/t-$CO_2$ (with sensitivity analysis at $80/t-$CO_2$) (in 2006 dollars for 2007 emissions), increasing at 2.4% per year thereafter. The final MY2011 CAFE rule also presented a range from $2 to $80/t-$CO_2$.

In the May 2009 proposal leading to today's final rule, EPA identified preliminary SCC estimates that spanned three orders of magnitude. EPA's May 2009 proposal also presented preliminary global SCC estimates developed from a survey analysis of the peer reviewed literature (i.e., meta analysis). The global mean values from the meta analysis were $68 and $40/t-$CO_2$ for discount rates of 2% and 3% respectively (in 2006 real dollars for 2007 emissions).[354]

Since publication of the May 2009 proposal, a federal interagency working group has established a methodology for selecting a range of interim SCC estimates for use in regulatory analyses. Today's final rule uses the five values for the SCC that are the outcome of this process. A complete description of the methodology used to generate this interim set of SCC estimates can be found in the RIA for this rule and in multiple other published rules, including a proposal to limit vehicle greenhouse gas emissions that requests public comment on the estimates and underlying methodology.[355]

It should be emphasized that the analysis here is preliminary. These interim estimates are being used for the short-term while an interagency group develops a more comprehensive characterization of the distribution of SCC values for future economic and regulatory analyses. The interim values should not be viewed as an expectation about the results of the longer-term process.

This process will allow the workgroup to explore questions raised in the May 2009 proposal as they are relevant to the development of SCC values for use in the long-

[353] For the purposes of this discussion, we present all values of the SCC as the cost per metric tonne of CO_2 emissions. Some discussions of the SCC in the literature use an alternative presentation of a dollar per metric ton of carbon. The standard adjustment factor is 3.67, which means, for example, that a SCC of $10 per ton of CO_2 would be equivalent to a cost of $36.70 for a ton of carbon emitted. Unless otherwise indicated, a "ton" refers to a metric ton.
[354] 74 FR 25094 (May 26, 2009).
[355] Federal Register 40 CFR Parts 86 and 600, September 28, 2009 "Proposed Rulemaking To Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Proposed Rule"

term. The workgroup may evaluate factors not currently captured in today's estimates due to time constraints, such as the quantification of additional impact categories where possible and an uncertainty analysis. The Administration will seek comment on all of the scientific, economic, and ethical issues before establishing improved estimates for use in future rulemakings.

The outcomes of the Administration's process to develop interim values are judgments in favor of a) global rather than domestic values, b) an annual growth rate of 3%, and c) interim global SCC estimates for 2007 (in 2007 dollars) of $56, $34, $20, $10, and $5 per metric ton of CO_2. As noted, this is an emphatically interim SCC value. The judgments herein will be subject to further scrutiny and exploration.

3. Application of Interim SCC Estimates to GHG Emissions Reductions

While no single rule or action can independently achieve the deep worldwide emissions reductions necessary to halt and reverse the growth of GHGs, the combined effects of multiple strategies to reduce GHG emissions domestically and abroad could make a major difference in the climate change impacts experienced by future generations.[356] The projected net GHG emissions reductions associated with the increased use of renewable fuels reflect an incremental change to projected total global emissions. Given that the climate response is projected to be a marginal change relative to the baseline climate, we estimate the marginal value of changes in climate change impacts over time and use this value to measure the monetized marginal benefits of the GHG emissions reductions projected for the increased renewable fuel volumes required by EISA.

Accordingly, EPA has used the set of interim, global SCC values described above to estimate the benefits of the increased use of renewable fuels. The interim SCC values for emissions in 2007, which reflect the Administration's interim interpretation of the current literature, are $5, $10, $20, $34, and $56, in 2007 dollars, and are based on a CO_2 emissions change of 1 metric ton in 2007. Table VIII.C.3-1 presents the interim SCC values for both the years 2007 and 2022 in 2007 dollars.

[356] The Supreme Court recognized in *Massachusetts v. EPA* that a single action will not on its own achieve all needed GHG reductions, noting that "[a]gencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop.'' See *Massachusetts v.* EPA, 549 U.S. at 524 (2007).

Table VIII.C.3-1
Interim SCC Schedule (2007$ per metric tonne of CO_2)

Year 5%	5% (Newell-Pizer)*	Average SCC from 3% and 5%	3% 3%	(Newell-Pizer)*
2007 $5	$10	$20	$34	$56
2022 $8	$16	$30	$53	$88

Note: The SCC values are dollar-year and emissions-year specific. These values are presented in 2007$, for individual year of emissions. To determine values for other years not presented in the table, use a 3% per year growth rate. SCC values represent only a partial accounting for climate impacts.
*SCC values are adjusted based on Newell and Pizer (2003) to account to future uncertainty in discount rates.

Table VIII.C.3-2 provides, for the low, base, and high cases, the average annual GHG emissions reductions in 2022. The annualized emissions reductions are multiplied by the SCC estimates for 2022 from Table VIII.C.3-1 to produce the average annual monetized benefit from the emissions reductions for CO_2-equivalent GHGs. This is equivalent to taking the time stream of emissions from the increase in renewable fuel volumes, multiplying them by the SCC (which is increasing at a rate of 3 percent per year), and then discounting the stream of benefits by 3 percent.

Table VIII.C.3-2
Average Annual Emissions Reduction (Million Metric Tonnes CO_2-e) and Monetized Benefits (Million 2007$) in 2022

Low	Case	Base Case	High Case
Emissions Reductions	136.104 138.41	1 140.291	
5%	$1,089 $1,107	$1,122	
5% (Newell-Pizer)	$2,178 $2,215	$2,245	
Average SCC from 3% and 5%	$4,138	$4,208	$4,265
3%	$7,186 $7,308	$7,407	
3% (Newell-Pizer)	$11,976 $12,17	9 $12,344	

Table VIII.C.3-3 provides, for the high, base, and low cases, the monetized benefits from the emissions reductions from the increase in renewable fuel volumes for CO_2-equivalent GHGs in 2022. The SCC estimates for 2022 increase at a rate of 3 percent per year, and are then multiplied by the stream of emissions for each respective year for 30 years. The monetized benefits in table VIII.C.3-3 represent the net present value of these emissions for 30 years using a discount rate of 7 percent.

Table VIII.C.3-3.
Monetized Benefits (Million 2007$) of RFS-2 Volumes in 2022
Using a 7% Discount Rate

High		Base	Low
5%	$606 $620	$631	
5% (Newell-Pizer)	$1,212 $1,239	$1,262	
Average SCC from 3% and 5%	$2,302	$2,355	$2,397
3%	$3,999 $4,089	$4,163	
3% (Newell-Pizer)	$6,665 $6,816	$6,939	

D. Criteria Pollutant Health and Environmental Impacts

1. Overview

This section describes EPA's analysis of the co-pollutant health and environmental impacts that can be expected to occur as a result of the increase in renewable fuel use throughout the period from initial implementation of the RFS2 rule through 2022. Although the purpose of this final rule is to implement the renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007, the increased use of renewable fuels will also impact emissions of criteria and air toxic pollutants and their resultant ambient concentrations. The fuels changes detailed in Section 3.1 of the RIA will influence emissions of VOCs, PM, NO_X, and SO_X and air toxics and affect exhaust and evaporative emissions of these pollutants from vehicles and equipment. They will also affect emissions from upstream sources such as fuel production, storage, distribution and agricultural emissions. Any decrease or increase in ambient ozone, $PM_{2.5}$, and air toxics associated with the increased use of renewable fuels will impact human health in the form of a decrease or increase in the risk of incurring premature death and other serious human health effects, as well as other important public health and welfare effects.

This analysis reflects the impact of the 2022 mandated renewable fuel volumes (the "RFS2 control case") compared with two different reference scenarios that include the use of renewable fuels: a 2022 baseline projection based on the RFS1-mandated volume of 7.1 billion gallons of renewable fuels, and a 2022 baseline projection based on the AEO 2007 volume of roughly 13.6 billion gallons of renewable fuels. [357] Thus, the results represent the impact of an incremental increase in ethanol and other renewable fuels. We note that the air quality modeling results presented in this final rule do not constitute the "anti-backsliding" analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality and health impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action.

[357] The 2022 modeled scenarios assume the following: RFS1 reference case assumes 6.7 Bgal/yr ethanol and 0.38 Bgal/yr biodiesel; AEO2007 reference case assumes 13.18 Bgal/yr ethanol and 0.38 Bgal/yr biodiesel; RFS2 control case assumes 34.14 Bgal/yr ethanol, 0.81 Bgal/yr biodiesel, and 0.38 Bgal/yr renewable diesel. Please refer to Chapter 3.3 and Table 3.3-1 for more information about the renewable fuel volumes assumed in the modeled analyses and the corresponding emissions inventories.

As can be seen in Section VI.D of this preamble, as well as in Section 3.4 of the RIA that accompanies this preamble, there are both increased and decreased concentrations of ambient criteria pollutants and air toxics. Overall, we estimate that the required renewable fuel volumes will lead to a net increase in criteria pollutant-related health impacts. By 2022, the final RFS2 volumes relative to both reference case scenarios (RFS1 and AEO2007), are projected to adversely impact $PM_{2.5}$ air quality over parts of the U.S., while some areas will experience decreases in ambient $PM_{2.5}$. As described in Section VI, ambient $PM_{2.5}$ is likely to increase as a result of emissions at biofuel production plants and from biofuel transport, both of which are more prevalent in the Midwest. PM concentrations are also likely to decrease in some areas. While the PM-related air quality impacts are relatively small, the increase in population-weighted national average $PM_{2.5}$ exposure results in a net increase in adverse PM-related human health impacts. (the increase in national population weighted annual average $PM_{2.5}$ is 0.006 μg/m3 and 0.002 μg/m3 relative to the RFS1 and AEO2007 reference cases, respectively).

The required renewable fuel volumes, relative to both reference scenarios, are also projected to adversely impact ozone air quality over much of the U.S., especially in the Midwest, Northeast and Southeast. These adverse impacts are likely due to increased upstream emissions of NOx in many areas that are NOx-limited (acting as a precursor to ozone formation). There are, however, ozone air quality improvements in some highly-populated areas that currently have poor air quality. This is likely due to VOC emission reductions at the tailpipe in urban areas that are VOC-limited (reducing VOC's role as a precursor to ozone formation). Relative to the RFS1 mandate reference case, the RFS2 volumes result in an increase in national ozone-related health impacts (population weighted maximum 8-hour average ozone increases by 0.177 ppb). Relative to the AEO2007 reference case, the RFS2 volumes result in an increase in national ozone-related health impacts (population weighted maximum 8-hour average ozone increases by 0.116 ppb).

The analysis of national-level $PM_{2.5}$- and ozone-related health and environmental impacts associated with the required renewable fuel volumes is based on peer-reviewed studies of air quality and human health effects (see US EPA, 2006 and US EPA, 2008).[358,359] We are also consistent with the benefits analysis methods that supported the recently proposed Portland Cement National Emissions Standards for Hazardous Air Pollutants (NESHAP) RIA (U.S. EPA, 2009a),[360] the proposed NO_2 primary NAAQS

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358 U.S. Environmental Protection Agency. (2006). *Final Regulatory Impact Analysis (RIA) for the Proposed National Ambient Air Quality Standards for Particulate Matter*. Prepared by: Office of Air and Radiation. Retrieved March, 26, 2009 at http://www.epa.gov/ttn/ecas/ria.html

359 U.S. Environmental Protection Agency. (2008). *Final Ozone NAAQS Regulatory Impact Analysis*. Prepared by: Office of Air and Radiation, Office of Air Quality Planning and Standards. Retrieved March, 26, 2009 at http://www.epa.gov/ttn/ecas/ria.html

360 U.S. Environmental Protection Agency (U.S. EPA). 2009a. Regulatory Impact Analysis: National Emission Standards for Hazardous Air Pollutants from the Portland Cement Manufacturing Industry. Office of Air Quality Planning and Standards, Research Triangle Park, NC. April. Available on the Internet at <http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementria_4-20-09.pdf>.

RIA (U.S. EPA, 2009b), [361] and the proposed Category 3 Marine Diesel Engines RIA (U.S. EPA, 2009c).[362] These methods are described in more detail in the RIA that accompanies this preamble. To model the ozone and PM air quality impacts of the required renewable fuel volumes, we used the Community Multiscale Air Quality (CMAQ) model (see Section VI.D). The modeled ambient air quality data serves as an input to the Environmental Benefits Mapping and Analysis Program (BenMAP).[363] BenMAP is a computer program developed by the U.S. EPA that integrates a number of the modeling elements used in previous analyses (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates.

The range of total national-level ozone- and PM-related monetized impacts associated with the required renewable fuel volumes is presented in Table VIII.D.1-1.[364] We present total monetized impacts based on the PM- and ozone-related premature mortality function used. Total monetized impacts therefore reflect the addition of each estimate of ozone-related premature mortality (each with its own row in Table VIII.D.1-1) to estimates of PM-related premature mortality. These estimates represent EPA's preferred approach to characterizing the best estimate of monetized impacts associated with the required renewable fuel volumes.

Emissions and air quality modeling decisions were made early in the analytical process and as a result, there are a number of important limitations and uncertainties associated with the air quality modeling analysis that must be kept in mind when considering the results. A key limitation of the analysis is that it employed interim emission inventories, which were enhanced compared to what was described in the proposal, but did not include some of the later enhancements and corrections of the final emission inventories presented in this FRM (see Section VI.A through VI.C of this preamble). Most significantly, our modeling of the air quality impacts of RFS2 relied upon interim inventories that assumed that ethanol will make up 34 of the 36 billion gallon renewable fuel mandate, that approximately 20 billion gallons of this ethanol will be in the form of E85, and that the use of E85 results in fewer emissions of direct $PM_{2.5}$ from vehicles. The emission impacts, air quality results and benefits analysis would be different if, instead of E85, more non-ethanol biofuels are used or mid-level ethanol blends are approved and utilized.

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[361] U.S. Environmental Protection Agency (U.S. EPA). 2009b. Proposed NO2 NAAQS Regulatory Impact Analysis (RIA). Office of Air Quality Planning and Standards, Research Triangle Park, NC. April. Available on the Internet at http://www.epa.gov/ttn/ecas/regdata/RIAs/proposedno2ria.pdf. Note: The revised NO2 NAAQS may be final by the publication of this action.

[362] U.S. Environmnetal Protection Agency (U.S. EPA). 2009c. Draft Regulatory Impact Analysis: Control of Emissions of Air Pollution from Category 3 Marine Diesel Engines. Office of Transportation and Air Quality, June. Available on the Internet at http://www.epa.gov/otaq/regs/nonroad/420d09002.htm. Note: The C3 rule may be final by the publication of this action.

[363] Information on BenMAP, including downloads of the software, can be found at http://www.epa.gov/ttn/ecas/ benmodels.html.

[364] Note that these impacts reflect the national total of PM-related benefits and disbenefits and ozone-related benefits and disbenefits. The sum of total of benefits and disbenefits yields a net negative benefit, or disbenefit. See Tables VIII.D.2-1 and VIII.D.2-2 for pollutant- and endpoint-specific incidence estimates and Table VIII.D.3-1 for pollutant- and endpoint specific monetized values.

In fact, as explained earlier in this preamble, our more recent analyses indicate that ethanol and E85 volumes are likely to be significantly lower than what we assumed in the interim inventories. Furthermore, the final emission inventories do not include vehicle-related PM reductions associated with E85 use, as discussed in Section VI.A through VI.C. There are additional, important limitations and uncertainties associated with the interim inventories that must be kept in mind when considering the results, which are described in more detail in Section VI. While it is difficult to describe the overall impact of these limitations and uncertainties on the quantified and monetized health impacts of the increased renewable fuel volumes without updating the air quality modeling analysis, we believe the results are still useful for describing potential national-level health impacts.

Additionally, after the air quality modeling was completed, we discovered an error in the way that $PM_{2.5}$ emissions from locomotive engines were allocated to counties in the inventory. The mismatched allocations between the reference and control scenarios resulted in $PM_{2.5}$ emission changes that were too high in some counties and too low in others, by varying degrees. As a result, we did not present the modeling results for specific localized $PM_{2.5}$ impacts in Section VI.D. However, because the error was random and offsetting, there was very little impact on national-level $PM_{2.5}$ emissions. An analysis of the error's impact on the national emission inventories found that direct $PM_{2.5}$ emissions were inflated by 8% relative to the AEO reference case and by 0.6% relative to the RFS1 reference case, leading to a small overestimation of national PM-related adverse health impacts. Note that this error did not impact other PM precursor inventories such as NOx and SO2. As a result, we have concluded that $PM_{2.5}$ modeling results are still informative for national-level benefits assessment, particularly given that other uncertainties in the $PM_{2.5}$ inventory (such as E85 usage**,** discussed below) have a more important (and offsetting) effect.

Table VIII.D.1-1
Estimated 2022 Monetized PM-and Ozone-Related Health Impacts from the Mandated Renewable Fuel Volumes[a]

2022 Total Ozone and PM Benefits, RFS2 Control Case Compared to RFS1 Reference Case[a]			
Premature Ozone Mortality Function	Reference To	tal Benefits (Billions, 2007$, 3% Discount Rate)[b,c]	Total Benefits (Billions, 2007$, 7% Discount Rate)[b,c]
Multi-city analyses	Bell et al., 2004	Total: -$1.4 to -$2.8 PM: -$0.92 to -$2.3 Ozone: -$0.52	Total: -$1.4 to -$2.6 PM: -$0.84 to -$2.0 Ozone: -$0.52
	Huang et al., 2005	Total: -$1.8 to -$3.1 PM: -$0.92 to -$2.3 Ozone: -$0.83	Total: -$1.7 to -$2.9 PM: -$0.84 to -$2.0 Ozone: -$0.83
	Schwartz, 2005	Total: -$1.7 to -$3.0 PM: -$0.92 to -$2.3 Ozone: -$0.77	Total: -$1.6 to -$2.8 PM: -$0.84 to -$2.0 Ozone: -$0.77
Meta-analyses	Bell et al., 2005	Total: -$2.5 to -$3.8 PM: -$0.92 to -$2.3 Ozone: -$1.6	Total: -$2.4 to -$3.6 PM: -$0.84 to -$2.0 Ozone: -$1.6
	Ito et al., 2005	Total: -$3.1 to -$4.5 PM: -$0.92 to -$2.3 Ozone: -$2.2	Total: -$3.0 to -$4.2 PM: -$0.84 to -$2.0 Ozone: -$2.2
	Levy et al., 2005	Total: -$3.1 to -$4.5 PM: -$0.92 to -$2.3 Ozone: -$2.2	Total: -$3.1 to -$4.3 PM: -$0.84 to -$2.0 Ozone: -$2.2
2022 Total Ozone and PM Benefits, RFS2 Control Case Compared to AEO Reference Case[a]			
Premature Ozone Mortality Function	Reference To	tal Benefits (Millions, 2007$, 3% Discount Rate)[b,c]	Total Benefits (Millions, 2007$, 7% Discount Rate)[b,c]
Multi-city analyses	Bell et al., 2004	Total: -$0.63 to -$1.0 PM: -$0.29 to -$0.70 Ozone: -$0.34	Total: -$0.60 to -$0.98 PM: -$0.26 to -$0.63 Ozone: -$0.34
	Huang et al., 2005	Total: -$0.84 to -$1.3 PM: -$0.29 to -$0.70 Ozone: -$0.55	Total: -$0.81 to -$1.2 PM: -$0.26 to -$0.63 Ozone: -$0.55
	Schwartz, 2005	Total: -$0.80 to -$1.2 PM: -$0.29 to -$0.70 Ozone: -$0.51	Total: -$0.77 to -$1.1 PM: -$0.26 to -$0.63 Ozone: -$0.51
Meta-analyses	Bell et al., 2005	Total: -$1.3 to -$1.8 PM: -$0.29 to -$0.70 Ozone: -$1.0	Total: -$1.3 to -$1.7 PM: -$0.26 to -$0.63 Ozone: -$1.0
	Ito et al., 2005	Total: -$1.7 to -$2.2 PM: -$0.29 to -$0.70 Ozone: -$1.5	Total: -$1.7 to -$2.1 PM: -$0.26 to -$0.63 Ozone: -$1.5
	Levy et al., 2005	Total: -$1.8 to -$2.2 PM: -$0.29 to -$0.70 Ozone: -$1.5	Total: -$1.7 to -$2.1 PM: -$0.26 to -$0.63 Ozone: -$1.5

Notes:
[a] Total includes premature mortality-related and morbidity-related ozone and $PM_{2.5}$ benefits. Range was developed by adding the estimate from the ozone premature mortality function to the estimate of $PM_{2.5}$-related premature mortality derived from either the ACS study (Pope et al., 2002) or the Six-Cities study (Laden et al., 2006).

[b] Note that total benefits presented here do not include a number of unquantified benefits categories. A detailed listing of unquantified health and welfare effects is provided in Table VIII.D.1-2.
[c] Results reflect the use of both a 3 and 7 percent discount rate, as recommended by EPA's Guidelines for Preparing Economic Analyses and OMB Circular A-4. Results are rounded to two significant digits for ease of presentation and computation.

The monetized estimates in Table VIII.D.1-1 include all of the human health impacts we are able to quantify and monetize at this time. However, the full complement of human health and welfare effects associated with PM and ozone remain unquantified because of current limitations in methods or available data. We have not quantified a number of known or suspected health effects linked with ozone and PM for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in heart rate variability). Additionally, we are unable to quantify a number of known welfare effects, including acid and particulate deposition damage to cultural monuments and other materials, and environmental impacts of eutrophication in coastal areas. These are listed in Table VIII.D.1-2.

Table VIII.D.1-2
Unquantified and Non-Monetized Potential Effects from the Mandated Renewable Fuel Volumes

Pollutant/Effects	Effects Not Included in Analysis - Changes in:
Ozone Health[a]	Chronic respiratory damage[b] Premature aging of the lungs[b] Non-asthma respiratory emergency room visits Exposure to UVb (+/-)[e]
Ozone Welfare	Yields for -commercial forests -some fruits and vegetables -non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Ecosystem functions Exposure to UVb (+/-)[e]
PM Health[c]	Premature mortality - short term exposures[d] Low birth weight Pulmonary function Chronic respiratory diseases other than chronic bronchitis Non-asthma respiratory emergency room visits Exposure to UVb (+/-)[e]
PM Welfare	Residential and recreational visibility in non-Class I areas Soiling and materials damage Damage to ecosystem functions Exposure to UVb (+/-)[e]
Nitrogen and Sulfate Deposition Welfare	Commercial forests due to acidic sulfate and nitrate deposition Commercial freshwater fishing due to acidic deposition Recreation in terrestrial ecosystems due to acidic deposition Existence values for currently healthy ecosystems Commercial fishing, agriculture, and forests due to nitrogen deposition Recreation in estuarine ecosystems due to nitrogen deposition Ecosystem functions Passive fertilization
CO Health	Behavioral effects
HC/Toxics Health[f]	Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde) Anemia (benzene) Disruption of production of blood components (benzene) Reduction in the number of blood platelets (benzene) Excessive bone marrow formation (benzene) Depression of lymphocyte counts (benzene) Reproductive and developmental effects (1,3-butadiene) Irritation of eyes and mucus membranes (formaldehyde) Respiratory irritation (formaldehyde) Asthma attacks in asthmatics (formaldehyde) Asthma-like symptoms in non-asthmatics (formaldehyde) Irritation of the eyes, skin, and respiratory tract (acetaldehyde) Upper respiratory tract irritation and congestion (acrolein)
HC/Toxics Welfare	Direct toxic effects to animals Bioaccumulation in the food chain Damage to ecosystem function Odor

Notes:
[a] The public health impact of biological responses such as increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection are likely partially represented by our quantified endpoints.
[b] The public health impact of effects such as chronic respiratory damage and premature aging of the lungs may be partially represented by quantified endpoints such as hospital admissions or premature mortality, but a number of other related health impacts, such as doctor visits and decreased athletic performance, remain unquantified.
[c] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.
[d] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort studies used in this analysis. However, the PM mortality results derived from the expert elicitation do take into account premature mortality effects of short term exposures.
[e] May result in benefits or adverse health impacts.
[f] Many of the key hydrocarbons related to this rule are also hazardous air pollutants listed in the Clean Air Act.

While there will be impacts associated with air toxic pollutant emission changes that result from the increased use of renewable fuels, we do not attempt to monetize those impacts. This is primarily because currently available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.[365] While EPA has since improved the tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics. EPA continues to work to address these limitations; however, we did not have the methods and tools available for national-scale application in time for the analysis of the final rule.[366]

2. Quantified Human Health Impacts

Tables VIII.D.2-1 and VIII.D.2-2 present the annual $PM_{2.5}$ and ozone health impacts in the 48 contiguous U.S. states associated with the required renewable fuel volumes relative to both the RFS1 and AEO reference cases for 2022. For each endpoint

[365] Science Advisory Board. 2001. NATA – Evaluating the National-Scale Air Toxics Assessment for 1996 – an SAB Advisory. http://www.epa.gov/ttn/atw/sab/sabrev.html.
[366] In April, 2009, EPA hosted a workshop on estimating the benefits or reducing hazardous air pollutants. This workshop built upon the work accomplished in the June 2000 Science Advisory Board/EPA Workshop on the Benefits of Reductions in Exposure to Hazardous Air Pollutants, which generated thoughtful discussion on approaches to estimating human health benefits from reductions in air toxics exposure, but no consensus was reached on methods that could be implemented in the near term for a broad selection of air toxics. Please visit http://epa.gov/air/toxicair/2009workshop.html for more information about the workshop and its associated materials.

presented in Tables VIII.D.2-1 and VIII.D.2-2, we provide both the mean estimate and the 90% confidence interval.

Using EPA's preferred estimates, based on the ACS and Six-Cities studies and no threshold assumption in the model of mortality, we estimate that the required renewable fuel volumes will result in between 110 and 270 cases of $PM_{2.5}$-related premature deaths annually in 2022 when compared to the RFS1 reference case. When compared to the AEO reference scenario, we estimate that the required renewable fuel volumes will result in between 33 and 85 cases of $PM_{2.5}$-related premature deaths annually in 2022 For ozone-related premature mortality, we estimate that national changes in ambient ozone will contribute to between 54 to 250 additional premature mortalities in 2022 as a result of the required renewable fuel volumes relative to the RFS1 scenario. When compared to the AEO reference scenario, we estimate that the required renewable fuel volumes will contribute to between 36 to 160 additional ozone-related premature mortalities in 2022.

Table VIII.D.2-1

Estimated $PM_{2.5}$-Related Health Impacts Associated with the Mandated Renewable Fuel Volumes[a]

Health Effect	2022 RFS2 Control Case Compared to RFS1 Reference Case (5th% - 95th%ile)	2022 RFS2 Control Case Compared to AEO Reference Case (5th% - 95th%ile)
Premature Mortality – Derived from Epidemiology Literature[b]		
Adult, age 30+, ACS Cohort Study (Pope et al., 2002)	-110 (-42 - -170)	-33 (-13 - -53)
Adult, age 25+, Six-Cities Study (Laden et al., 2006)	-270 (-150 - -400)	-85 (-46 - -120)
Infant, age <1 year (Woodruff et al., 1997)	0 (0 - -1)	0 (0 - -1)
Chronic bronchitis (adult, age 26 and over)	-65 (-26 - -110)	-19 (-4 - -18)
Non-fatal myocardial infarction (adult, age 18 and over)	-180 (-65 - -290)	-51 (-19 - -84)
Hospital admissions - respiratory (all ages)[c] -2	6 (-25 - -26)	-7 (-5 - -8)
Hospital admissions - cardiovascular (adults, age >18)[d]	-55 (-44 - -70)	-12 (-9 - -16)
Emergency room visits for asthma (age 18 years and younger)	-180 (-110 - -260)	-99 (-58 - -140)
Acute bronchitis, (children, age 8-12)	-160 (0 - -330)	-50 (0 - -100)
Lower respiratory symptoms (children, age 7-14)	-1,900 (-910 - -2,900)	-600 (-290 - -910)
Upper respiratory symptoms (asthmatic children, age 9-18)	-1,400 (-450 - -2,400)	-450 (-140 - -750)
Asthma exacerbation (asthmatic children, age 6-18)	-1,700 (-190 - -4,800)	-540 (-60 - -1,500)
Work loss days	-11,000 (-10,000 - -13,000)	-3,200 (-2,800 - -3,700)
Minor restricted activity days (adults age 18-65)	-68,000 (-57,000 - -78,000)	-19,000 (-16,000 - -22,000)

Notes:

[a] Note that negative incidence expressed in this table reflects disbenefits; in other words, an increase in total aggregated national-level PM-related health impacts. Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.

[b] PM-related adult mortality based upon the American Cancer Society (ACS) Cohort Study (Pope et al., 2002) and the Six-Cities Study (Laden et al., 2006). Note that these are two alternative estimates of adult mortality and should not be summed. PM-related infant mortality based upon a study by Woodruff, Grillo, and Schoendorf, (1997).[367]

[c] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

[d] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic

[367] Woodruff, T.J., J. Grillo, and K.C. Schoendorf. 1997. “The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Air Pollution in the United States.” *Environmental Health Perspectives* 105(6):608-612.

heart disease, dysrhythmias, and heart failure.

Table VIII.D.2-2
Estimated Ozone-Related Health Impacts Associated with the Mandated Renewable Fuel Volumes[a]

Health Effect	2022 RFS2 Control Case Compared to RFS1 Reference Case (5^{th}% - 95^{th}%ile)	2022 RFS2 Control Case Compared to AEO Reference Case (5^{th}% - 95^{th}%ile)
Premature Mortality, All ages[b]		
Multi-City Analyses		
Bell et al. (2004) – Non-accidental	-54 (-17 - -92)	-36 (-10 - -62)
Huang et al. (2005) – Cardiopulmonary	-90 (-31 - -149)	-59 (-18 - -100)
Schwartz (2005) – Non-accidental	-83 (-24 - -140)	-55 (-13 - -97)
Meta-analyses:		
Bell et al. (2005) – All cause	-180 (-80 - -270)	-120 (-49 - -180)
Ito et al. (2005) – Non-accidental	-240 (-140 - -350)	-160 (-90 - -230)
Levy et al. (2005) – All cause	-250 (-170 - -330)	-160 (-110 - -220)
Hospital admissions- respiratory causes (adult, 6. and older)[c]	-470 (-20 - -860)	-310 (-5 - -580)
Hospital admissions -respiratory causes (childrer under 2)	-83 (-24 - -140)	-190 (-52 - -330)
Emergency room visit for asthma (all ages)	-260 (0 - -740)	-180 (0 - -510)
Minor restricted activity days (adults, age 18-65)	-300,000 (-110,000 - -500,000)	-200,000 (-59,000 - -340,000)
School absence days	-110,000 (-35,000 - -180,000)	-75,000 (-19,000 - -120,000)

Notes:
[a] Note that negative incidence expressed in this table reflects disbenefits; in other words, an increase in total aggregated national-level ozone-related health impacts. Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States. Note that negative incidence estimates represent additional cases of an endpoint related to pollution increases associated with the increased use of renewable fuels.
[b] Estimates of ozone-related premature mortality are based upon incidence estimates derived from several alternative studies: Bell et al. (2004); Huang et al. (2005); Schwartz (2005) ; Bell et al. (2005); Ito et al. (2005); Levy et al. (2005). The estimates of ozone-related premature mortality should therefore not be summed.
[c] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

3. Monetized Impacts

Table VIII.D.3-1 presents the estimated monetary value of the increase in ozone and $PM_{2.5}$-related health effects incidence associated with the required renewable fuel volumes relative to both the RFS1 and AEO reference cases for 2022. All monetized estimates are stated in 2007\$. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the year 2022. As the table indicates, total adverse health impacts are driven primarily by the increase in $PM_{2.5}$- and ozone-related premature fatalities.

Our estimate of monetized adverse health impacts in 2022 for the required renewable fuel volumes relative to the RFS1 reference case, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, are between \$1.4 billion and \$4.5 billion, assuming a 3 percent discount rate, or between \$1.4 billion and \$4.3 billion, assuming a 7 percent discount rate. The total monetized adverse health impacts in 2022 for the required renewable fuel volumes relative to the AEO reference case are between \$0.63 billion and \$2.2 billion assuming a 3 percent discount rate, and between \$0.60 billion and \$2.1 billion assuming a 7 percent discount rate. We are unable to quantify a number of health and environmental impact categories (see Table VIII.D.1-2). These unquantified impacts may be substantial, although their magnitude is highly uncertain.

Table VIII.D.3-1
Estimated Monetary Value of Health and Welfare Effect Incidence (in millions of 2007$) [a,b]

		2022 RFS2 Control Case Compared to RFS1 Reference Case	2022 RFS2 Control Case Compared to AEO Reference Case
$PM_{2.5}$-Related Health Effect		Estimated Mean Value of Reductions (5th and 95th %ile)	
Premature Mortality – Derived from Epidemiology Studies[c,d,]	Adult, age 30+ - ACS study (Pope et al., 2002) 3% discount rate 7% discount rate	-$860 (-$100 - -$2,300) -$770 (-$91 - -$2,000)	-$270 (-$32 - -$700) -$240 (-$28 - -$630)
	Adult, age 25+ - Six-cities study (Laden et al., 2006) 3% discount rate 7% discount rate	-$2,200 (-$29 - -$5,500) -$2,000 (-$26 - -$5,000)	-$680 (-$90 - -$1,700) -$620 (-$81 - -$1,600)
	Infant Mortality, <1 year – (Woodruff et al. 1997)	-$4.0 (-$3.0 - -$15)	-$1.7 (-$1.3 - -$6.7)
Chronic bronchitis (adults, 26 and over)		-$32 (-$2.5 - -$110)	-$9.4 (-$0.72 - -$33)
Non-fatal acute myocardial infarctions 3% discount rate 7% discount rate		-$23 (-$4.1 - -$58) -$23 (-$3.8 - -$58)	-$6.6 (-$1.0 - -$17) -$6.4 (-$0.95 - -$16)
Hospital admissions for respiratory causes		-$0.39 (-$0.19 - -$0.57	-$0.11 (-$0.06 - -$0.17)
Hospital admissions for cardiovascular causes		-$1.5 (-$0.96 - -$2.1)	-$0.33 (-$0.20 - -$0.45)
Emergency room visits for asthma		-$0.07 (-$0.04 - -$0.10)	-$0.04 (-$0.02 - -$0.06)
Acute bronchitis (children, age 8–12)		-$0.01 ($0 - -$0.03)	-$0.004 ($0 - -$0.01)
Lower respiratory symptoms (children, 7–14)		-$0.04 (-$0.01 - -$0.07)	-$0.01 (-$0.004 - -$0.02)
Upper respiratory symptoms (asthma, 9–11)		-$0.04 (-$0.01 - -$0.10)	-$0.01 (-$0.004 - -$0.03)
Asthma exacerbations		-$0.09 (-$0.009 - -$0.28)	-$0.03 (-$0.003 - -$0.09)
Work loss days		-$1.7 (-$1.5 - -$1.9)	-$0.49 (-$0.42 - -$0.55)
Minor restricted-activity days (MRADs)		-$4.3 (-$2.5 - -$6.2)	-$1.2 (-$0.69 - -$1.7)
Ozone-related Health Effect			
Premature Mortality, All ages – Derived from Multi-city	Bell et al., 2004	-$480 (-$51 - -$1,300)	-$320 (-$32 - -$880)

analyses	Huang et al., 2005	-$800 (-$90 - -$2,200)	-$530 (-$56 - -$1,400)
	Schwartz, 2005	-$740 (-$76 - -$2,000)	-$490 (-$48 - -$1,300)
Premature Mortality, All ages – Derived from Meta-analyses	Bell et al., 2005	-$1,600 (-$200 - -$4,000)	-$1,000 (-$130 - -$,700)
	Ito et al., 2005	-$2,200 (-$290 - -$5,400)	-$1,400 (-$190 - -$3,600)
	Levy et al., 2005	-$2,200 (-$300 - -$5,300)	-$1,400 (-$200 - -$3,500)
Hospital admissions- respiratory causes (adult, 65 and older)		-$11 (-$0.49 - -$20)	-$7.4 (-$0.13 - -$14)
Hospital admissions- respiratory causes (children, under 2)		-$3.0 (-$1.0 - -$4,9)	-$1.9 (-$0.52 - -$3.3)
Emergency room visit for asthma (all ages)		-$0.10 (-$0.009 - -$0.26)	-$0.07 (-$0.008 - -$0.18)
Minor restricted activity days (adults, age 18-65)		-$19 (-$6.4 - -$35)	-$13 (-$3.6 - -$24)
School absence days		-$10 (-$3.1 - -$16)	-$6.7 (-$1.7 - -$11)

Notes:
[a] Negatives indicate a disbenefit, or an increase in health effect incidence. Monetary impacts are rounded to two significant digits for ease of presentation and computation. PM and ozone impacts are nationwide.
[b] Monetary impacts adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2022)
[c] Valuation assumes discounting over the SAB recommended 20 year segmented lag structure. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses.

4. What Are the Limitations of the Health Impacts Analysis?

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Limitations of the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, such as premature mortality associated with exposure to carbon monoxide. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes which can be quantified. These general uncertainties in the underlying scientific and economics literature, which can lead to valuations that are higher or lower, are discussed in detail in the RIA and its supporting references. Key uncertainties that have a bearing on the results of the benefit-cost analysis of the coordinated strategy include the following:

- The exclusion of potentially significant and unquantified benefit categories (such as health, odor, and ecological benefits of reduction in air toxics, ozone, and PM);
- Errors in measurement and projection for variables such as population growth;
- Uncertainties in the estimation of future year emissions inventories and air quality;

- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C-R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

As Table VIII.D.3-1 indicates, total impacts are driven primarily by the additional premature mortalities estimated to occur each year. Some key assumptions underlying the premature mortality estimates include the following, which may also contribute to uncertainty:

- Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been completely established, the weight of the available epidemiological, toxicological, and experimental evidence supports an assumption of causality. The impacts of including a probabilistic representation of causality were explored in the expert elicitation-based results of the PM NAAQS RIA.
- All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM related to fuel use in mobile sources may differ significantly from PM precursors released from electric generating units and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.
- The C-R function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that may be in attainment with $PM_{2.5}$ standards and those that are at risk of not meeting the standards.
- There is uncertainty in the magnitude of the association between ozone and premature mortality. The range of ozone impacts associated with the increased use of renewable fuels is estimated based on the risk of several sources of ozone-related mortality effect estimates. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council, a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health impacts of reducing ozone exposure.[368] EPA has requested advice from the National Academy of Sciences on how best to quantify uncertainty in the relationship between ozone exposure and premature mortality in the context of quantifying health impacts.

Acknowledging the omission of a range of health and environmental impacts, and the uncertainties mentioned above, we present a best estimate of the total monetized impacts based on our interpretation of the best available scientific literature and methods

[368] National Research Council (NRC), 2008. Estimating Mortality Risk Reduction and Economic Benefits from Controlling Ozone Air Pollution. The National Academies Press: Washington, D.C.

supported by EPA's technical peer review panel, the Science Advisory Board's Health Effects Subcommittee (SAB-HES). The National Academies of Science (NRC, 2002) has also reviewed EPA's methodology for analyzing air pollution-related health and environmental impacts. EPA addressed many of these comments in the analysis of the final PM NAAQS.[369,370] This analysis incorporates this most recent work to the extent possible.

E. Summary of Costs and Benefits

Presented in this section are a summary of costs, benefits, and net benefits of the renewable fuel volumes required by final RFS2 program. Table VIII.E–1 shows the estimated annual societal costs and benefits of the increased use of renewable fuels in 2022. The table also presents estimated annual net benefits for 2022. In this table, fuel savings are presented as negative costs associated with the increased use of renewable fuels (rather than positive savings). Note that all costs and benefits are presented in annual terms; we were unable to estimate a stream of costs and benefits for many of the cost-benefit categories and were therefore unable to estimate net present value.

Table VIII.E-1 presents the benefits of reduced GHG emissions—and consequently the annual quantified benefits (i.e., total benefits) and quantified net benefits—for each of five interim SCC values considered by EPA. As discussed in Section VIII.C, there is a very high probability (very likely according to the IPCC) that the benefit estimates from GHG reductions are underestimates because, in part, models used to calculate SCC values do not include information about impacts that have not been quantified.

Table VIII.E-1
Quantified Costs and Benefits of the Volumes Required by RFS2 Relative to the AEO Reference Case in 2022 (Billions of 2007 dollars)[371]

2	022
Quantified Annual Costs	
Overall Fuel Cost[a]	-$11.8
Quantified Annual Benefits	
Reduced GHG Emissions (by SCC)	

[369] National Research Council (NRC). 2002. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. The National Academies Press: Washington, D.C.
[370] U.S. Environmental Protection Agency. October 2006. *Final Regulatory Impact Analysis (RIA) for the Proposed National Ambient Air Quality Standards for Particulate Matter.* Prepared by: Office of Air and Radiation. Available at HTTP://www.epa.gov/ttn/ecas/ria.html.
[371] In this table, we have included only the estimates from the sector models as they provided a more detailed breakdown of costs and benefits. We have excluded estimates of the agricultural sector impacts of the RFS2 in Table VIII F-1 since these impacts are considered economic rents.

SCC 5%	$0.6 to $1.1
SCC 5% Newell-Pizer	$1.2 to $2.2
SCC from 3% and 5%	$2.4 to $4.2
SCC 3%	$4.1 to $7.3
SCC 3% Newell-Pizer	$6.8 to $12.2
$PM_{2.5}$- and Ozone-Related Benefits[b,c]	-$0.63 to -$2.2
Energy Security Impacts	$2.6
Total Benefits (by SCC)	
SCC 5%	$1 to $3.1
SCC 5% Newell-Pizer	$1.6 to $4.2
SCC from 3% and 5%	$2.8 to $6.2
SCC 3%	$4.5 to $9.3
SCC 3% Newell-Pizer	$7.2 to $14.2
Quantified Net Benefits	
Net Benefits (by SCC)	
SCC 5%	$13 to $15
SCC 5% Newell-Pizer	$13 to $16
SCC from 3% and 5%	$15 to $18
SCC 3%	$16 to $21
SCC 3% Newell-Pizer	$19 to $26

[a] Negative costs represent fuel savings from decreased gasoline and diesel consumption.
[b] Negative benefits indicate a disbenefit, or an increase in monetized health impacts. Total includes premature mortality-related and morbidity-related ozone and $PM_{2.5}$ impacts. Range was developed by adding the estimate from the ozone premature mortality function to the estimate of $PM_{2.5}$-related premature mortality derived from either the ACS study (Pope et al., 2002) or the Six-Cities study (Laden et al., 2006).
[c] The $PM_{2.5}$-related impacts presented in this table assume a 3% discount rate in the valuation of premature mortality to account for a twenty-year segmented cessation lag. If a 7% discount rate had been used, the values would be approximately 9% lower.

IX. Impacts on Water

A. Background

As the production of biofuels increases as required by this rule, there may be adverse impacts on both water quality and water quantity affecting drinking water sources and ecological habitats. The impacts could come from several different pathways: growing crops for the biofuel feedstock as well as production, storage, and distribution of the biofuels. Increased production of biofuel crops may lead to changes in the management of cropland and the use of fertilizer and pesticides that could lead to greater loadings of nutrients, pesticides, and sediment to our water resources. While there are methods to minimize and mitigate the effects on water resources, there is still a potential to impact both human health and the environment. Since both the irrigation of corn and ethanol production use large quantities of water, the supply of water could also be significantly affected in some locations.

1. Agriculture and Water Quality

There are three major pathways for contaminants to reach water from agricultural lands: run off from the land's surface, man-made ditches or subsurface tile drains, and leaching to ground water. Many factors influence the potential for contaminants such as fertilizers, sediment, and pesticides to reach water from agricultural lands, including: soil type, slope, climate, crop type, and management. Management of agricultural lands can take many forms, but key factors include nutrient and pesticide application rates and application methods, tillage, use of conservation practices and crop rotations by farmers, and acreage and intensity of artificially drained lands.

To examine the potential water-related impacts of growing crops for biofuels, EPA focused its analysis on corn production for several reasons. First, corn acres have increased dramatically, 20% from 2006 to 2007. Although corn acres have since declined somewhat, total corn acres in 2009 remained the second highest since 1946.372 Second, corn kernels are currently the predominant and most economically viable feedstock for significant ethanol production. In addition, corn stover (stalks, leaves) will likely be the predominant feedstock for cellulosic ethanol production in the Upper Mississippi River Basin where we modeled water quality impacts. And third, corn production can contribute significantly to water pollution. Corn has the highest fertilizer and pesticide use per acre and accounts for the largest share of nitrogen fertilizer use among all crops373. Corn generally utilizes only 40 to 60 percent of the applied nitrogen fertilizer or the residual organic nitrogen from sources such as manure or soybeans. The remaining nitrogen is available to leave the field and run off to surface waters, leach into ground water, or volatilize to the air where it can return to water through depositional processes.

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[372]U.S. Department of Agriculture, National Agricultural Statistics Service, ''Crop Production'', August 12, 2009, available online at: http://usda.mannlib.cornell.edu/usda/current/CropProd/CropProd-08-12-2009.pdf

[373] Committee on Water Implications of Biofuels Production in the United States, National Research Council, 2008, Water implications of biofuels production in the United States, The National Academies Press, Washington, DC, 88 pp.

Over the past 20 years, corn has been increasingly grown in rotation with other crops, especially soybeans. As corn prices increase relative to prices for other crops, more farmers choose to grow corn every year (continuous corn). Continuous corn production results in significantly greater nitrogen losses annually than a corn-soybean rotation and lower yields per acre. In response, farmers may add higher rates of nitrogen fertilizer to try to match yields of corn grown in rotation. Growing continuous corn also increases the viability of pests such as corn rootworm. Farmers may increase the use of pesticides to control these pests. As corn acres increase, use of the common herbicides like atrazine and glyphosate (e.g. Roundup) may also increase.

High corn prices may encourage farmers to grow corn on lands that are marginal for row crop production such as hay land or pasture. Typically, agricultural producers apply far less fertilizers and pesticides on pasture land than land in row crops. Corn yield on these marginal lands will be lower and may require higher fertilizer rates. Disturbances of these soils can release nitrogen that has been stored in the soil. Since nitrogen fertilizer prices are tied to oil prices, fertilizer costs have fluctuated. How agricultural producers have responded to these changes in both corn and fertilizer prices is unclear.

Artificial drainage is another important factor in determining the losses of nutrients from cropland. Artificial drainage consists either of subsurface tiles/pipes or man-made ditches that move water from wet soils to surface waters so crops can be planted. In a few areas, drains move water to wells and then groundwater instead of to surface water. Artificial drainage has transformed large expanses of historic wetland soils into productive agriculture lands. However, the artificial drains or ditches also move nutrients and pesticides more quickly to surface waters without any of the attenuation that would occur if these contaminants moved through soils or wetlands. The highest proportion of tile drainage occurs in the Upper Mississippi and the Ohio-Tennessee River basins in areas of intensive corn production.374 Manmade ditches predominate in areas like the Eastern Shore of the Chesapeake Bay.

The increase in corn production and prices may also have significant impacts on voluntary conservation programs funded by the U.S. Department of Agriculture (USDA). Conservation programs provide important funding to help agricultural producers implement practices to protect water quality and other resources. As land values increase due to higher crop prices, USDA payments may not keep up with the need for farmers and tenant farmers, to make an adequate return. For example, the cost of farmland in Iowa increased an average of 18% in 2007 from 2006 prices.

Both land retirement programs, like the Conservation Reserve Program (CRP), and working land programs, like the Environmental Quality Incentives Program (EQIP), can be affected. Under CRP, USDA contracts with farmers to take land out of crop production to plant grasses or trees. Generally farmers put land into CRP because it is less productive and has other

[374] U.S. Environmental Protection Agency, EPA Science Advisory Board, Hypoxia in the northern Gulf of Mexico, EPA–SAB–08–003, 275 p, available online at: *http://yosemite.epa.gov/sab/sabproduct.nsf/C3D2F27094E03F90852573B800601D93/$File/EPA–SAB–08–003complete.unsigned.pdf*

characteristics that make the cropland more environmentally sensitive, such as high erosion rates. CRP provides valuable environmental benefits both for water quality and for wildlife habitat. Midwestern states, where much of U.S. corn is grown, tend to have lower CRP reenrollment rates than the national average. Under EQIP, USDA makes cost-share payments to farmers to implement conservation practices. Some of the most cost-effective practices implemented through these conservation programs include: riparian buffers; crop rotation; appropriate rate, timing, and method of fertilizer application; cover crops; and, on tile-drained lands, treatment wetlands and controlled drainage. If producers believe that participation in conservation programs may reduce their profits, they may be less willing to participate and/or require higher payments to offset perceived losses.

The water quality impacts of agricultural cellulosic feedstocks such as corn stover and switchgrass are unknown, since cellulosic ethanol is not currently produced commercially. Corn stover appears to be one of the most viable feedstock for cellulosic ethanol, especially in the Corn Belt states. When left in the field, corn stover maintains the soil organic carbon which has many benefits as a source of nutrients, preventing erosion by wind and water, and increasing soil aeration and water infiltration. If corn stover is overharvested, there may be impacts to both soil quality and water quality. Unlike corn, switchgrass is a native, perennial crop that does not require high inputs of fertilizers or pesticides. As a perennial crop, there is limited sediment runoff compared to annual crops. There is very minimal acreage of switchgrass grown at the present time, so it is difficult to predict what inputs farmers will use to cultivate it as a commercial crop. Some concern has been expressed about farmers increasing fertilizer application rates and irrigation on switchgrass to increase yields.

2. Ecological Impacts

Nitrogen and phosphorus enrichment due to human activities is one of the leading problems facing our nation's lakes, reservoirs, and estuaries. Nutrient enrichment also has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; and impairs aesthetic and recreational use. Excess nutrients can lead to excessive growth of algae in rivers and streams, and aquatic plants in all waters. For example, declines in invertebrate community structure have been correlated directly with increases in phosphorus concentration. High concentrations of nitrogen in the form of ammonia are toxic to aquatic animals. Excessive levels of algae have also been shown to be damaging to invertebrates. Finally, fish and invertebrates will experience growth problems and can die if either oxygen is depleted or pH increases are severe. Both of these conditions are symptoms of eutrophication. As a biologic system becomes more enriched by nutrients, different species of algae may spread and species composition can shift.

Nutrient pollution is widespread. Although the most widely known examples of significant nutrient impacts are in the Gulf of Mexico and the Chesapeake Bay, there are known impacts in over 80 estuaries/bays, and thousands of rivers, streams, and lakes. Waterbodies in virtually every state and territory in the U.S. are impacted by nutrient-related degradation. Reducing nutrient pollution is a priority for EPA.

3. Impacts to the Gulf of Mexico

According to the National Research Council, nutrients and sediment are the two primary water quality problems in the Mississippi River Basin and the Gulf of Mexico.[375] Production of corn for ethanol may exacerbate these existing serious water quality problems. Nitrogen fertilizer applications to corn are already the major source of total nitrogen loadings to the Mississippi River. A large area of low oxygen, or hypoxia, forms in the Gulf of Mexico every year, often called the ''dead zone.'' The primary cause of the hypoxia is excess nutrients (nitrogen and phosphorus) from the Upper Midwest flowing into the Mississippi River to the Gulf. These nutrients trigger excessive algal growth (or eutrophication) resulting in reduced sunlight, loss of aquatic habitat, and a decrease in oxygen dissolved in the water. Hypoxia threatens commercial and recreational fisheries in the Gulf because fish, shrimp, and other aquatic species cannot live in the low oxygen waters.

The 2008 hypoxic zone was measured at 8,000 square miles, the second largest since measurements began in 1985.376 In 2009 models predicted an even larger hypoxic zone, but it was measured at only 3,000 square miles. A combination of below average high flows on the Mississippi River and winds that mixed Gulf waters are the likely causes of the reduced size of the 2009 zone. The Mississippi River/Gulf of Mexico Watershed Nutrient Task Force's ''Gulf Hypoxia Action Plan 2008'' calls for a 45% reduction in both nitrogen and phosphorus reaching the Gulf to reduce the size of the zone.377 The Action Plan states that an additional reduction in nitrogen and phosphorus beyond the 45% would be necessary to account for increased corn production for ethanol and climate change impacts.

Alexander, et al.378 modeled the sources of nutrient loadings to the Gulf of Mexico using the USGS SPARROW model. They estimated that agricultural sources contribute more than 70% of the delivered nitrogen and phosphorus. Corn and soybean production accounted for 52% of nitrogen delivery and 25% of the phosphorus delivery.

Several recent scientific reports have estimated the impact of increasing ethanol feedstock acres in the Gulf of Mexico watershed. Donner and Kucharik's 379 study showed

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[375] Committee on the Mississippi River and the Clean Water Act, National Research Council, 2008, Mississippi River Water Quality and the Clean Water Act: Progress, Challenges, and Opportunities, The National Academies Press, Washington, DC, 252 pp.

[376] Louisiana Universities Marine Consortium, 2009, 'Gulf of Mexico Dead Zone Surprising Small, but Severe, available online at: *http://www.gulfhypoxia.net/Research/Shelfwide%20Cruises/2009/Files/Press_Release.pdf*

[377] Mississippi River/Gulf of Mexico Watershed Nutrient Task Force, 2008, Gulf hypoxia action plan 2008 for reducing, mitigating, and controlling hypoxia in the northern Gulf of Mexico and improving water quality in the Mississippi River basin, 61 p., Washington, DC, available online at: *http://www.epa.gov/msbasin/actionplan.htm*

[378] Alexander, R.B., Smith, R.A., Schwarz, G.E., Boyer, E.W., Nolan, J.V., and Brakebill, J.W., 2008, Differences in phosphorus and nitrogen delivery to the Gulf of Mexico from the Mississippi River basin, Environmental Science and Technology, v. 42, no. 3, p. 822–830, available online at: *http://pubs.acs.org/cgi-bin/abstract.cgi/esthag/2008/42/i03/abs/es0716103.html*

[379] Donner, S. D. and Kucharik, C. J., 2008, Corn-based ethanol production compromises goal of reducing nitrogen export by the Mississippi River, PNAS, v. 105, no. 11, p. 4513–4518, available online at: *http://www.pnas.org/content/105/11/4513.full*

increases in nitrogen export to the Gulf as a result of increasing corn ethanol production from 2007 levels to 15 billion gallons in 2022. They concluded that the expansion of corn-based ethanol production could make it almost impossible to meet the Gulf of Mexico nitrogen reduction goals without a ''radical shift'' in feed production, livestock diet, and management of agricultural lands. The study estimated a mean dissolved inorganic nitrogen load increase of 10% to 18% from 2007 to 2022 to meet the 15 billion gallon corn ethanol goal. EPA's Science Advisory Board report to the Mississippi River/Gulf of Mexico Watershed Task Force estimated that corn grown for ethanol will result in an additional national annual loading of almost 300 million pounds of nitrogen. An estimated 80% of that nitrogen loading or 238 million pounds will occur in the Mississippi-Atchafalaya River Basin and contribute nitrogen to the hypoxia in the Gulf of Mexico. The results of a study by Costello, et al. indicate that moving from corn to switchgrass and corn stover to produce ethanol will result in a 20% decrease in the nitrate outputs from the Mississippi-Atchafalaya River Basin. This decrease is not enough to meet the EPA target for reduction of the hypoxic zone reduction.380

B. Upper Mississippi River Basin Analysis

To provide a quantitative estimate of the impact of the increased use of renewable fuels and production of corn ethanol generally on water quality, EPA conducted an analysis that modeled the changes in loadings of nitrogen, phosphorus, and sediment from agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB drains approximately 189,000 square miles, including large parts of the states of Illinois, Iowa, Minnesota, Missouri, and Wisconsin. Small portions of Indiana, Michigan, and South Dakota also lie within the basin. EPA selected the UMRB because it is representative of the many potential issues associated with ethanol production, including its connection to major water quality concerns such as Gulf of Mexico hypoxia, large corn production, and numerous ethanol production plants.

On average the UMRB contributes about 39% of the total nitrogen loads and 26% of the total phosphorus loads to the Gulf of Mexico.377 The high percentage of nitrogen from the UMRB is primarily due to the large inputs of fertilizer for agriculture and the 60% of cropland that is artificially drained by tiles. Since the mid 1990s, the annual nitrate-nitrogen flux has steadily decreased. The Science Advisory Board report attributes this decline to higher amount of nitrogen removed during harvest, due to higher crop yields. For the same time period, phosphorus inputs increased 12%.

1. <u>SWAT Model</u>

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient and sediment loads from changes in agricultural production in the UMRB. SWAT is a physical

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[380] Costello, C.; Griffin, W.M.; Landis, A.E.; Matthew, H. S., 2009, Impact of biofuel crop production on the formation of hypoxia in the Gulf of Mexico, Environmental Science and Technology, *43* (20), pp 7985–7991

process model developed to quantify the impact of land management practices in large, complex watersheds.381

2. AEO 2007 Reference Case

In order to assess alternative potential future conditions within the UMRB, EPA developed a SWAT model of a reference case scenario of current conditions against which to analyze the future impact of increased corn production. For the NPRM, we used a 2005 baseline. For the final rule, we revised the baseline to correspond with the agricultural analysis described in Section VIII.A. Therefore we used the corn ethanol production baseline from the Annual Energy Outlook (AEO) 2007 report382 as our reference case. We assumed that 33% of the corn produced in the UMRB was converted to corn ethanol, based on estimates from USDA.383 This baseline does not include corn ethanol produced at the volumes required by this rulemaking. The analysis assumes that no cellulosic ethanol, including ethanol produced from corn stover, would be produced in the reference case since the AEO report did not include cellulosic ethanol production in its estimates.

The SWAT model was applied (i.e., calibrated) to the UMRB using 1960 to 2001 weather data and flow and water quality data from 13 USGS gages on the main stem of the Mississippi River. The 42-year SWAT model runs were performed and the results analyzed to establish runoff, sediment, nitrogen, and phosphorous loadings from each of the 131 8-digit HUC subwatersheds and the larger 4-digit subbasins, along with the total outflow from the UMRB and at the various USGS gage sites along the Mississippi River. These results provided the Reference Scenario model values to which the future alternatives are compared.

Physical structures that disconnect fertile floodplains with seasonal fluctuation of stream and river levels also affect water quantity and quality by altering the ability of these soils to serve as a sink for nutrient rich waters. In lieu of data on where these structures are or may be constructed, these effects were not modeled.

3. Reference Cases and RFS2 Control Case

To assess the impacts of the increased use of corn ethanol, we modeled an RFS2 Control Case and compared it to both the AEO 2007 Reference Case and the RFS1 Mandate Reference Case for the years 2010, 2015, 2020, and 2022. The RFS2 national corn ethanol volumes of 11.24 billion gallons a year (BGY) for 2010, and 15 BGY for 2016 to 2022 were adjusted for the UMRB. Annual increases in corn yield of 1.23% were built into the future

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[381] Gassman, P.W., Reyes, M.R., Green, C.H., Arnold, J.G., 2007, The soil and water assessment tool: Historical development, applications, and future research directions. Transactions of the American Society of Agricultural and Biological Engineers, v. 50, no. 4, p. 1211–1240. *http://www.card.iastate.edu/environment/items/asabe_swat.pdf*

[382] U. S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2007 With Projections to 2030, February 2007, available on-line at: *http://tonto.eia.doe.gov/ftproot/forecasting/0383(2007).pdf*

[383] U.S. Department of Agriculture, USDA Agricultural Projections to 2018, February 2009, available on-line at: *http://www.ers.usda.gov/Publications/OCE091/*

scenarios. National average corn yields have been increasing primarily due to favorable weather conditions and improvement in practices to reduce stress on the corn plants from excess water, drought, and pests. Fewer corn acres were needed to meet ethanol production goals in the Control Case scenario after 2015 due to those yield increases. Corn acres increased 9% in 2022 between the AEO 2007 Reference Case and the RFS2 (No Stover) Control Case. We were not able to model the impacts of corn stover removal at this time, so the analysis only reflects the impacts of increased use of corn grain for renewable fuel use.

Tables IX.B.3-1 through IX.B.3-3 compare the model outputs for nitrogen, phosphorus, and sediment between the AEO 2007 Reference Case and the RFS2 (No Stover) Control Case scenarios for the years 2010, 2015, 2020, and 2022. Land load is the total amount of nitrogen or phosphorus that reaches a stream within the UMRB. The total outflow is the nitrogen, phosphorus, or sediment measured at the outlet of the UMRB at Grafton, Illinois after accounting for in-stream loses due to uptake or assimilation. These results only estimate loadings from the Upper Mississippi River basin, not the entire Mississippi River watershed. As noted earlier, the UMRB contributes about 39% of the total nitrogen loads and 26% of total phosphorus loads to the Gulf of Mexico. The decreasing nutrient load over time is likely attributable to the increased average corn yield per acre, resulting in greater plant uptake of nitrogen and fewer corn acres planted to reach the ethanol production requirements of this rule.

Table IX.B.3–1
Average annual nitrogen loads: comparison of AEO 2007 Reference Case to the 2022 RFS2 (No Stover) Control Case (% difference in parentheses)

	AEO 2007 Reference Case		2022 RFS2 (No Stover) Control Case	
Model Run	Total Land Load, million lbs	Total Outflow, million lbs	Total Land Load, million lbs	Total Outflow, million lbs
2010	1948	1470	1944 (-0.21)	1467 (-0.20)
2015	1911	1441	1946 (1.83)	1469 (1.94)
2020	1887	1421	1912 (1.32)	1442 (1.48)
2022	1877	1413	1897 (1.07)	1430 (1.20)

About 24 to 26 % of the nitrogen and phosphorus leaving agricultural fields was assimilated (taken by aquatic plants or volatilized) before reaching the outlet of the UMRB. The assimilated nitrogen is not necessarily eliminated as an environmental concern. Five percent or more of the nitrogen can be converted to nitrous gas, a powerful greenhouse gas that has 300 times the climate warming potential of carbon dioxide, the major greenhouse. Thus, a water pollutant becomes an air pollutant until it is either captured through biological sequestration or converted fully to elemental nitrogen.

Table IX.B.3–2
Average annual phosphorus loads: comparison of AEO 2007 Reference Case to the 2022 RFS2 (No Stover) Control Case (% difference in parentheses)

	AEO 2007 Reference Case		2022 RFS2 (No Stover) Control Case	
Model Run	Total Land Load, million lbs	Total Outflow, million lbs	Total Land Load, million lbs	Total Outflow, million lbs
2010	180.0	133.8	179.9 (-0.06)	133.7 (-0.07)
2015	178.2	132.3	179.6 (0.79)	133.6 (0.98)
2020	177.0	131.3	178.2 (0.68)	132.4 (0.84)
2022	176.5	130.9	177.6 (0.62)	131.8 (0.69)

Total sediment outflow showed very little change over all scenarios. This result is primarily due to corn stover remaining on the field following harvest and therefore reducing sediment transport to water.

Table IX.B.3-3
Average annual sediment loads: comparison of AEO 2007 Reference Case to the 2022 RFS2 Control Case (% difference in parentheses)

	2007 AEO	2022 Control Volume Case
Model Run	Total Outflow, million tons	Total Outflow, million tons
2010	6.231	6.232 (0.02)
2015	6.221	6.233 (0.19)
2020	6.214	6.224 (0.16)
2022	6.211	6.220 (0.14)

The relationship between the number of acres of corn needed to produce ethanol and the crop yield is a complex relationship. Increased demand for corn based ethanol will not always result in increases in corn acres. Our modeling demonstrated that in less than a decade, increasing corn yields may counter the need for increased corn production resulting in the number of acres of corn stabilizing and additional nutrient and sediment loadings decreasing from the earlier peaks.

At this time, we are not able to assess the impact of these additional loadings on the size of the Gulf of Mexico hypoxia zone or water quality within the UMRB. For more details on the analysis, including comparisons with the RFS1, see Chapter 6 in the RIA.

4. Case Study

To evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB, we also modeled the Raccoon River watershed in central Iowa. The criteria for choosing this watershed included: percentage of corn area representative of the UMRB, stream segments included in EPA’s 303(d) list of impaired waters due to high nutrient levels, biorefinery plants, drinking water intakes, and observed streamflow and water quality data.

Nearly 88% of the watershed is in agriculture. 75% of the watershed produces corn and soybeans, mostly in rotation. Hay and other row crops are produced on the remaining agriculture land. The city of Des Moines makes up about 8% of the watershed. The state of Iowa has listed numerous stream segments of the Raccoon River as impaired.

The case study used the same assumptions and scenarios as those used for the UMRB analysis. SWAT-simulated streamflow and water quality (total nitrogen and phosphorus, and sediment loadings) were calibrated against observed data at both monthly and yearly time steps.

As in the UMRB study, nitrogen loads to water increased for the future scenarios, though at a greater rate. Future phosphorus loads decreased in the Raccoon River model, where they had shown minor increases in the UMRB model. For the Raccoon River, there was a greater decrease in sediment load, which is the likely cause for the decrease in phosphorus loadings.

5. Sensitivity Analysis

Using the existing UMRB SWAT model, a sensitivity analysis was conducted on a number of important meteorological and management related factors. The goal was to further understand the model characteristics and sensitivities to parameters and input forcing functions that control the model response for the key environmental indicators of concern. Scenarios were constructed using four factors: fertilization application threshold, corn residue removal, daily air temperature, and daily precipitation. The results of the analysis showed that rainfall and temperature are the most influential factors for all model outputs: water yield, total nitrogen and phosphorus loadings, and sediment loadings. These results underscored the importance of representing these two driving factors accurately in hydrologic modeling. Corn residue removal noticeably reduced nutrient loading into streams while increasing sediment loads. However, since corn residue is the main source of organic nitrogen and phosphorus, the removal of the residue leads to the need for higher nutrient inputs in the growing season. The fertilization application threshold scenario did not tangibly impact water yield and sediment loading. The findings from this study indicated that future climate change could greatly influence water availability and pollution from corn cropland.

C. Additional Water Issues

The full water quality and water quantity impacts resulting from corn ethanol production go beyond the ability of our model. For example, the model does not account for fresh water constraints in irrigated agriculture in corn producing areas or predict future increases in drainage of agricultural lands. The following issues are summarized to provide additional context about the broader range of potential impacts. See Chapter 6 in the RIA for more discussion of these issues.

1. Chesapeake Bay Watershed

In May 2009, President Obama issued Executive Order 13508 on Chesapeake Bay Restoration and Protection. The order established a Federal Leadership Committee, chaired by EPA, and with senior representatives from the departments of Agriculture, Commerce, Defense, Homeland Security, Interior, and Transportation. In November 2009, these federal agencies released a draft strategy which contains a range of approaches for accelerating cleanup of the nation's largest estuary and its vast watershed.384

The draft strategy calls for increased accountability and performance from pollution control, habitat protection and land conservation programs at all levels of government, including an expanded use of regulatory authorities to address pollution control and additional voluntary and market-based solutions – particularly when it comes to habitat protection and land conservation programs. The proposed actions are in response to overwhelming scientific evidence that the health of the Chesapeake Bay remains exceptionally poor, despite the concerted restoration efforts of the past 25 years.

Agricultural lands contribute more nutrients to the Chesapeake Bay than any other land use. To estimate the increase in nutrient loads to the Bay from changes to agricultural crop production from 2005 to 2008, the Chesapeake Bay Program Watershed Model Phase 4.3 and Vortex models were utilized. Total nitrogen loads increased by almost 2.4 million pounds from an increase of almost 66,000 corn acres. As agriculture land use shifts from hay and pasture to more intensively fertilized row crops, this analysis estimates that nitrogen loads increase by 8.8 million pounds.

2. Ethanol Production and Distribution

a. Production

There are three principal sources of discharges to water from ethanol plants: reject water from water purification, cooling water blowdown, and off-batch ethanol. Most ethanol facilities use onsite wells to produce the process water for the ethanol process. Groundwater sources are generally not suitable for process water because of their mineral content. Therefore, the water must be treated, commonly by reverse osmosis. For every two gallons of pure water produced, about a gallon of brine is discharged as reject water from this process. Most estimates of water consumption in ethanol production are based on the use of clean process water and neglect the water discharged as reject water.

The largest source of wastewater discharge is reverse osmosis reject water from process water purification. The reverse osmosis process concentrates groundwater minerals to levels where they can have water quality impacts. There is really no means of ''treating'' these ions to reduce toxicity, other than further concentration and disposal, or use of in-stream dilution. Some facilities have had to construct long pipelines to get access to dilution so they can meet water quality standards. Ethanol plants also discharge cooling water blowdown, where some water is discharged to avoid the buildup of minerals in the cooling system. These brines are similar to the reject water described above. In addition, if off-batch ethanol product or process water is discharged, the waste stream can have high Biochemical Oxygen Demand (BOD) levels. BOD

[384] Federal Leadership Committee for the Chesapeake Bay, November 9, 2009, Executive Order 13508: Draft Strategy for Protecting and Restoring the Chesapeake Bay, available on-line at: http://executiveorder.chesapeakebay.net/

directly affects the amount of dissolved oxygen in rivers and streams. The greater the BOD, the more rapidly oxygen is depleted in the stream. The consequences of high BOD are the same as those for low dissolved oxygen: aquatic organisms become stressed, suffocate, and die.

Older generation production facilities used four to six gallons of process water to produce a gallon of ethanol, but newer facilities use less than three gallons of water in the production process. Most of this water savings is gained through improved recycling of water and heat in the process. Water supply is a local issue, and there have been concerns with water consumption as new plants go online. Some facilities are tapping into deeper aquifers as a source of water. These deeper water resources tend to contain higher levels of minerals and this can further increase the concentration of minerals in reverse osmosis reject water. Geographic impacts of water use vary. A typical plant producing 50 million gallons of ethanol per year uses a minimum of 175 million gallons of water annually. In Iowa, water consumption from ethanol refining accounts for about seven percent of all industrial water use, and is projected to be 14% by 2012—or about 50 million gallons per day.

b. Distillers Grain with Solubles

Distillers grain with solubles (DGS) is an important co-product of ethanol production. About one-third of the corn processed into ethanol is converted into DGS. DGS has become an increasingly important feed component for confined livestock. DGS are higher in crude protein (nitrogen) and three to four times higher in phosphorus relative to traditional feeds. When nitrogen and phosphorus are fed in excess of the animal's needs, these nutrients are excreted in the manure. When manure is applied to crops at rates above their nutrient needs or at times the crop can not use the nutrients, the nutrients can run off to surface waters or leach into ground waters.

Livestock producers can limit the potential pollution from manure applications to crops by implementing comprehensive nutrient management. Due to the substantially higher phosphorus content of manure from livestock fed DGS, producers will potentially need significantly more acres to apply the manure so that phosphorus will not be applied at rates above the needs of the crops. This is a particularly important concern in areas where concentrated livestock production already produces more phosphorus in the manure than can be taken up by crops or pasture land in the vicinity.

Several recent studies have indicated that DGS may have an impact on food safety. Cattle fed DGS have a higher prevalence of a major food-borne pathogen, E. coli O157, than cattle without DGS in their diets.385 More research is needed to confirm these studies and devise methods to eliminate the potential risks.

c. Ethanol Leaks and Spills from Fueling Stations

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[385] Jacob, M. D., Fox, J. T., Drouillard, J. S., Renter, D. G., Nagaraja, T. G., 2008, Effects of dried distillers' grain on fecal prevalence and growth of *Escherichia coli* O157 in batch culture fermentations from cattle, Applied and Environmental Microbiology, v. 74, no. 1, p. 38–43, available online at: http://aem.asm.org/cgi/content/abstract/74/1/38

The potential for exposure to fuel components and/or additives can occur when underground fuel storage tanks leak fuel into ground water that is used for drinking water supplies or when spills occur from aboveground tanks or distribution systems that contaminate surface drinking water supplies. or surface waters. Additionally, in surface waters, rapid biodegradation of ethanol can result in depletion of dissolved oxygen with potential mortality to aquatic life.

Regarding leaks or spills and drinking water impacts, ethanol biodegrades quickly and is not necessarily the pollutant of greatest concern in these situations. Instead, ethanol's high biodegradability shifts the subsurface geochemistry, which can cause the reduced biodegradation of benzene, toluene, and xylene (up to 50% for toluene and 95% for benzene).[386] The plume of BTEX compounds from a fuel spill (benzene, toluene, ethylbenzene and xylenes) can extend as much as 70% farther in ground water and can persist longer, thereby increasing potential exposures to these compounds.[387]

Ethanol leak and spills from the approximately 600,000 gas stations in the U.S, could have a significant impact on water quality and drinking water supplies. Urban areas, that rely on ground water for drinking water would be affected most, especially where are existing water shortages.

With the increasing use of ethanol in the fuel supply nationwide, it is important to understand the impact of ethanol on the existing tank infrastructure. Federal regulations require that underground storage tank (UST) systems be compatible with the fuel stored. Because much of the current underground storage tank equipment was designed and tested for use with petroleum fuels, there may be many UST systems currently in use that contain materials that are incompatible with ethanol blends greater than 10%. Combined with the fact that ethanol is more corrosive than petroleum, there is concern regarding the increased potential for leaks from existing distribution systems, terminals and gas stations and subsequent impacts on water supplies. Given the practical challenges of determining the age and materials of underground storage equipment at approximately 233,000 federally regulated facilities, it may be difficult or impossible to confirm the compatibility of current underground storage tanks and other tank-related hardware with ethanol blends. Further discussion of challenges in retail distribution are discussed in Section 1.6 of the RIA.

In 2008, there were 7,400 reported releases from underground storage tanks. Therefore, EPA is undertaking analyses designed to assess the potential impacts of ethanol blends on tank infrastructure and leak detection systems and determine the resulting water quality impacts.

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[386] Mackay, D.M., de Sieyes, N. R., Einarson, M.D., Feris, K.P., Pappas, A.A., Wood, I.A., Jacobson, L., Justice, L.G., Noske, M.N., Scow, K.M., and Wilson, J.T., 2006, Impact of ethanol on the natural attenuation of benzene, toluene, and o-Xylene in a normally sulfate-reducing aquifer, Environmental Science & Technology, v. 40, p. 6123-6130.

[387] Ruiz-Aguilar, G. M. L.; O'Reilly, K.; Alvarez, P. J. J., 2003, Forum: A comparison of benzene and toluene plume lengths for sites contaminated with regular vs. ethanol-amended gasoline, Ground Water Monitoring and Remediation, v. 23, p. 48–53.

3. Biodiesel Plants

Biodiesel plants use much less water than ethanol plants. Water is used for washing impurities from the finished product. Water use is variable, but is usually less than one gallon of water for each gallon of biodiesel produced. Larger well-designed plants use water more sparingly, while smaller producers use more water. Some facilities recycle washwater, which reduces water consumption. The levels of BOD (biological oxygen demand) in process wastewater from biodiesel plants is highly variable. Most production processes produce washwater that has very high BOD levels. The high BOD levels of these wastes can overload and disrupt municipal treatment plants.

Crude glycerin is an important side product from the biodiesel process and is about 10% of the final product. Although there is a commercial market for glycerin, the rapid development of the biodiesel industry has caused a glut of glycerin production and many facilities dispose of their glycerin. Poor handling of crude glycerin has resulted in disruptions at sewage treatment plants and fish kills.

4. Water Quantity

Water demand for crop production for ethanol could potentially be much larger than biorefinery demand. According to the National Research Council, the demand for water to irrigate crops for biofuels will not have an impact on national water use, but it is likely to have significant local and regional impacts.373 The impact is crop and region specific, but could be especially great in areas where new acres are irrigated.

5. Drinking Water

Increased corn production will result in the increased use of fertilizers and herbicides which can drain to surface water or ground water sources used by public water systems and individual home owners on private wells. This may increase the occurrence of nitrate, nitrite, and the herbicide Atrazine in sources of drinking water. The U.S. Geological Survey evaluated the fate and transport of herbicides in surface water, ground water, and in precipitation in the Midwest during the 1990s. The results of these studies showed the occurrence and temporal distribution of herbicides and their associated degradation products in reservoir outflows.[388]

Under the Safe Drinking Water Act, EPA has established enforceable standards for these contaminants that apply to public water systems. Source water contamination by these chemicals may raise local water system costs for treatment or for increased energy to pump water where ethanol production is accelerating the long running depletion of aquifers e.g., pumping extra water to grow the additional corn in addition to pumping extra water to process the corn into

[388] Scribner, E.A., Thurman, E.M., Goolsby, D.A., Meyer, M.T., Battaglin, W.A., and Kolpin, D.W., 2005, Summary of significant results from studies of triazine herbicides and their degradation products in surface water, ground water, and precipitation in the Midwestern United States during the 1990s: U.S. Geological Survey Scientific Investigations Report 2005–5094, 27 p.

ethanol. There is also an (often concurrent) risk of exhausting local drinking water supplies where aquifers have been severely depleted.

X. Public Participation

Many interested parties participated in the rulemaking process that culminates with this final rule. This process provided opportunity for submitting written public comments following the proposal that we published on May 26, 2009 (74 FR 24904), and we considered these comments in developing the final rule. In addition, we held a public hearing on the proposed rulemaking on June 9, 2009, and we have considered comments presented at the hearing.

Throughout the rulemaking process, EPA met with stakeholders including representatives from the fuel and renewable fuels industries, the agricultural sector, and others. The program we are finalizing today was developed as a collaborative effort with these stakeholders.

We have prepared a detailed Summary and Analysis of Comments document, which describes the comments we received on the proposal and our response to each of these comments. The Summary and Analysis of Comments is available in the docket for this rule at the Internet address listed under **ADDRESSES**, as well as on the Office of Transportation and Air Quality Web site (www.epa.gov/otaq/renewablefuels/index.htm). In addition, comments and responses for key issues are included throughout this preamble.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Regulatory Impact Analysis, which is available in the docket for this rulemaking and at the docket internet address listed under **ADDRESSES** in the first part of this final rule.

B. Paperwork Reduction Act

The information collection requirements in this have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

Information to be collected under this rulemaking includes compliance reports and reports regarding the generation and assignment of, and transactions involving, RINs. This final rule involves registration requirements, recordkeeping and reporting. Affected parties include producers of renewable fuels, importers, domestic and foreign refiners, exporters, domestic and foreign parties who own RINs, and biofuel feedstock producers. Individual items of recordkeeping and reporting are discussed in great detail in this preamble and in the "Supporting Statement for the Renewable Fuels Standard (RFS2) Final Rule," which has been placed in the public docket.

We estimate the annual recordkeeping and reporting burden for this rule at 3.2 hours per response. We estimate a total of 1,060,026 respondents; 4,781,126 responses; 1,485,008 burden hours, and a total cost associated with responding of $112,872,105. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act

1. Overview

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the renewable fuel volume requirements of RFS2 on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (see table below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

Industry[a]	Defined as small entity by SBA if:	NAICS[a] codes
Gasoline and diesel fuel refiners	≤1,500 employees	324110
a- North American Industrial Classification System		

2. Background

Section 1501 of the Energy Policy Act of 2005 (EPAct) amended section 211 of the Clean Air Act (CAA) by adding section 211(o) which required the Environmental Protection Agency (EPA) to promulgate regulations implementing a renewable fuel program. EPAct specified that the regulations must ensure a specific volume of renewable fuel to be used in gasoline sold in the U.S. each year, with the total volume increasing over time. The goal of the program was to reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and help transition to alternatives to petroleum in the transportation sector.

The final Renewable Fuels Standard (RFS1) program rule was published on May 1, 2007, and the program began on September 1, 2007. Per EPAct, the RFS1 program created a specific annual level for minimum renewable fuel use that increases over time—resulting in a requirement that 7.5 billion gallons of renewable fuel be blended into gasoline (for highway use only) by 2012. Under the RFS1 program, compliance is based on meeting the required annual renewable fuel volume percent standard (published annually in the Federal Register by EPA) through the use of Renewable Identification Numbers, or RINs, 38-digit serial numbers assigned to each batch of renewable fuel produced. For obligated parties (those who must meet the annual volume percent standard), RINs must be acquired to show compliance.

The Energy Independence and Security Act of 2007 (EISA) amended section 211(o), and the RFS program, by requiring higher volumes of renewable fuels, to result in 36 billion gallons of renewable fuel by 2022. EISA also expanded the purview of the RFS1 program by requiring that these renewable fuels be blended into gasoline and diesel fuel (both highway and nonroad). This expanded the pool of regulated entities, so the obligated parties under the RFS program will now include certain refiners, importers, and blenders of these fuels that were not previously covered by the RFS1 program. In addition to the total renewable fuel standard required by EPAct, EISA added standards for three additional types of renewable fuels to the program (advanced biofuel, cellulosic biofuel, and biomass-based diesel) and requires compliance with all four standards.

As required by section 609(b) of the RFA, as amended by SBREFA, EPA also conducted outreach to small entities and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements.

3. Summary of Potentially Affected Small Entities

The small entities that will potentially be subject to the RFS program include: domestic refiners that produce gasoline and/or diesel and importers of gasoline and/or diesel into the United States. Based on 2007 data, EPA believes that there are about 95 refiners of gasoline and diesel fuel. Of these, EPA believes that there are currently 17 refiners, owning 20 refineries, producing gasoline and/or diesel fuel that meet the SBA small entity definition of having 1,500 employees or less. Further, we believe that three of these refiners own refineries that do not meet the Congressional "small refinery" definition.[389] It should be noted that because of the dynamics in the refining industry (i.e., mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status under the RFS2 rule could be different than this estimate.

4. Reporting, Recordkeeping, and Compliance

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. As discussed above in Sections II.J and III.A, the compliance requirements under the RFS2 rule are in many ways similar to those required under the RFS1 rule, with some modifications (e.g., those to account for the new requirements of EISA). New provisions being finalized in today's action include the new EPA Moderated Transaction System (EMTS) which allows for "real-time" reporting of RIN generation transactions, and the ability for small blenders to "delegate" their RIN-separation responsibilities to the party directly upstream. Please see Sections II and III of this preamble for more detailed information on these and other registration, recordkeeping, reporting, and compliance requirements of this final rule.

[389] EPAct defined a "small refinery" as a refinery with a crude throughput of no more than 75,000 barrels of crude per day (at CAA section 211(o)(1)(K)). This definition is based on facility size and is different than SBA's small refiner definition (which is based on company size). A small refinery could be owned by a larger refiner that exceeds SBA's small entity standards. SBA's size standards were established to set apart those businesses which are most likely to be at an inherent economic disadvantage relative to larger businesses.

5. Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to this rule. The primary related Federal rules are: the first Renewable Fuel Standard (RFS1) rule (*72 FR 23900, May 1, 2007*), the RFS1 Technical Amendment Direct Final Rulemaking (*73 FR 57248, October 2, 2008*)[390], and Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder (proposed rule: *74 FR 44442, August 28, 2009*; final rule: *signed December 22, 2009*).

6. Steps Taken to Minimize the Significant Economic Impact on Small Entities

a. Significant Panel Findings

We convened a Small Business Advocacy Review Panel (SBAR Panel, or the Panel), which considered many regulatory options and flexibilities that would help mitigate potential adverse effects on small businesses as a result of the increased volumes of renewable fuel required by RFS2. During the SBREFA Panel process, the Panel sought out and received comments on the regulatory options and flexibilities that were presented to Small Entity Representatives (SERs) and Panel members. The major flexibilities and hardship relief provisions that were recommended by the Panel were proposed and some are being finalized today (for more information regarding the Panel process, see the SBREFA Final Panel Report, which is available in the public docket for this rule).

b. Outreach With Small Entities (and the Panel Process)

As required by section 609(b) of the RFA as amended by SBREFA, EPA conducted outreach to small entities and convened a SBAR Panel prior to proposing the RFS2 rule to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements.

As part of the SBAR Panel process, we conducted outreach with representatives from the various small entities that would be affected by the rule. We met with these SERs to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries. The Panel received written comments from the SERs, specifically on regulatory alternatives that could help to minimize the rule's impact on small businesses. In general, SERs stated that they believed that small refiners would face challenges in meeting the new standards. More specifically, they voiced concerns with respect to the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and cost), and the desire for a RIN system review.

The Panel agreed that EPA should consider the issues raised by the SERs (and discussions had by the Panel itself) and that EPA should consider comments on flexibility alternatives that would help to mitigate any negative impacts on small businesses. Alternatives discussed throughout the Panel process included those offered in previous or current EPA

[390] This Direct Final Rule corrects minor typographical errors and provides clarification on existing provisions in the RFS1 regulations.

rulemakings, as well as alternatives suggested by SERs and Panel members, and the Panel recommended that all be considered in the development of the rule.

A summary of the Panel's recommendations, what the Agency proposed, and what is being finalized today is discussed below. A detailed discussion of the regulatory alternatives and hardship provisions discussed and recommended by the Panel can be found in the SBREFA Final Panel Report, and a discussion of the provisions being finalized today is located in Section III.E of this preamble.

c. Panel Recommendations, Proposed Provisions, and Provisions Being Finalized

The purpose of the Panel process is to solicit information as well as suggested flexibility options from the SERs, and the Panel recommended that EPA continue to do so during the development of the RFS2 rule. Recognizing the concerns about EPA's authority to provide extensions to a subset of small refineries (i.e., those that are owned by small refiners) different from that provided to small refineries in section 211(o)(9), the Panel recommended that EPA continue to evaluate this issue, and that EPA request comment on its authority and the appropriateness of providing extensions beyond those authorized by section 211(o)(9) for small refineries operated by a small refiner. The Panel also recommended that EPA propose to provide the same extension provision of 211(o)(9) to small refiners who do not own small refineries as is provided for small refiners who do own small refineries.

i. *Delay in Standards*

The RFS1 program regulations provide small refiners who operate small refineries as well as small refiners who do not operate small refineries with a temporary exemption from the standard through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the RFS2 standards. EPA evaluated a temporary exemption for at least some of the four required RFS2 standards for small refiners. The Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute. However, the Panel recognized that EPA has serious concerns about its authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9), since Congress specifically addressed an extension for small refineries in that provision.

The Panel did recommend that EPA propose other avenues through which small refineries and small refiners could receive extensions of the temporary exemption. These avenues were a possible extension of the temporary exemption for an additional two years following a study of small refineries by the Department of Energy (DOE) and provisions for case-by-case economic hardship relief.

We proposed and took comment on the recommendations of the Panel and SERs above. As discussed in section III.E of this preamble, based on our analysis and further review of the provisions and the DOE Small Refinery Study, we have decided to finalize continuing the small refinery and small refiner exemption finalized in RFS1 through December 31, 2010 for all small refiners.

ii. *Phase-in*

Small refiner SERs' suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, EPA has serious concerns about its authority to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall "consist of a single applicable percentage that applies to all categories of persons specified" as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, as discussed above, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. Thus the Panel recommended that EPA should invite comment on a phase-in, but not propose such a provision.

We took comment on this provision, however we are not finalizing this provision, as we continue to believe that a phase-in of the applicable standards would in fact result in different standards for small refiners.

iii. *RIN-Related Flexibilities*

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. In the RFS1 program, EPA allows for 20% of a previous year's RINs to be "rolled over" and used for compliance in the following year. We noted during the Panel process that a provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. Further, we noted our belief that since the concept of a rollover cap was not mandated by section 211(o), EPA believes that there may be an opportunity to provide appropriate flexibility in this area to small refiners under the RFS2 program but only if it is determined in the DOE small refinery study that there is a disproportionate effect warranting relief. The Panel recommended that EPA request comment on increasing the RIN rollover cap percentage for small refiners, and further that EPA should request comment on an appropriate level of that percentage. The Panel also recommended that EPA invite comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties.

We proposed a change to the RIN rollover cap, and took comment on the concept of allowing RINs to be used interchangeably for small refiners only. As noted above in section III of this preamble, we are not finalizing RIN-related provisions in today's action. As highlighted in the NPRM, we continue to believe that the concept of interchangeable RINs for small refiners only fails to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel). Further, given the findings from the DOE study, if small refineries and small refiners do not face disproportionate economic hardship, then we do not believe that we have the basis for granting such additional relief beyond what Congress already provided. Thus, small refiners will be held to the same RIN rollover cap as other obligated parties.

iv. *Program Review*

With regard to the suggested program review, EPA raised the concern that this could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and that this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, the SBA and OMB Panel members stated that they believe that a program review could be helpful to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As EPA will be publishing a Federal Register notice annually, the Panel recommended that EPA include an update of RIN system progress (e.g., RIN trading, RIN availability, etc.) in this notice and that the results of this evaluation be considered in any request for case-by-case hardship relief.

We did propose that in the annual notice of the RFS standards that EPA must publish in the Federal Register, we would also include information to help inform industry about the RIN system. We also proposed that information from the annual Production Outlook Reports that producers and importers must submit to EPA, as well as information required in EMTS reports, could be used in the annual Federal Register notice to update RIN system progress. However, during the development of the final rule, it became evident that there could be instances where we would want to report out RIN system information on a more frequent basis than just once a year. Thus we are finalizing that we will report out elements of RIN system progress; but such information will be reported via other means (e.g., the RFS website (www.epa.gov/otaq/renewablefuels/index.htm), EMTS homepage, etc.). Additionally, we will also publish annual summaries of the Production Outlook Reports.

v. *Extensions of the Temporary Exemption Based on a Study of Small Refinery Impacts*

The Panel recommended that EPA propose in the RFS2 program the provision at 40 CFR 80.1141(e) extending the RFS1 temporary exemption for at least two years for any small refinery that DOE determines would be subject to disproportionate economic hardship if required to comply with the RFS2 requirements.

Section 211(o)(9)(A)(ii) required that by December 31, 2008, DOE was to perform a study of the economic impacts of the RFS requirements on small refineries to assess and determine whether the RFS requirements would impose a disproportionate economic hardship on small refineries, and submit this study to EPA. Section 211(o)(9) also provided that small refineries found to be in a disproportionate economic hardship situation would receive an extension of the temporary exemption for at least two years.

The Panel also recommended that EPA work with DOE in the development of the small refinery study, specifically to communicate the comments that SERs raised during the Panel process.

We did not propose and are not finalizing this hardship provision given the outcome of the DOE small refinery study. In the small refinery study, "EPACT 2005 Section 1501 Small Refineries Exemption Study", DOE's finding was that there is no reason to believe that any small refinery would be disproportionately harmed by inclusion in the proposed RFS2 program. This finding was based on the fact that there appeared to be no shortage of RINs available under RFS1, and EISA has provided flexibility through waiver authority (per section 211(o)(7)). Further, in the case of the cellulosic biofuel standard, cellulosic biofuel allowances can be provided from EPA at prices established in EISA (see regulation section 80.1455). DOE thus determined that no small refinery would be subject to disproportionate economic hardship under the proposed RFS2 program, and that the small refinery exemption should not be extended beyond December 31, 2010. DOE noted in the study that, if circumstances were to change and/or the RIN market were to become non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption (as stated in regulation section 80.1441).

As discussed in section III.E of this preamble, since the only small refinery study available for us to use as a basis for whether or not to grant small refineries an automatic two-year extension of the exemption is the study that was performed in 2008, we had to use this study to develop this final rule. EPAct directs EPA to consider the DOE small refinery study in assessing the impacts to small refineries, and we interpret this to mean that any extension past December 31, 2010 has to be tied to the DOE Study. Further, since that study found that there was no disproportionate economic impact on small refineries, we cannot grant an automatic additional extension for small refineries or small refiners (except on a case-by-case hardship basis). However, this does not preclude small refiners from applying for case-by-case extensions of the small refiner temporary exemption.

Note that if the revised DOE study (see Section III.E.3 of this preamble) finds that there is a disproportionate economic impact, we will revisit the extension of the temporary exemption at that point.

vi. *Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship*

While SERs did not specifically comment on the concept of hardship provisions for the upcoming proposal, the Panel noted that under CAA section 211(o)(9)(B) small refineries may petition EPA for case-by-case extensions of the small refinery temporary exemption on the basis of disproportionate economic hardship. Refiners may petition EPA for this case-by-case hardship relief at any time.

The Panel recommended that EPA propose in the RFS2 program a case-by-case hardship provision for small refineries similar to that provided at 40 CFR 80.1141(e)(1). The Panel also recommended that EPA propose a case-by-case hardship provision for small refiners that do not operate small refineries that is comparable to that provided for small refineries under section 211(o)(9)(B), using its discretion under CAA section 211(o)(3)(B). This would apply if EPA does not adopt an automatic extension for small refiners, and would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. The Panel recommended that EPA take into consideration the results of the annual update of RIN system progress and the DOE small refinery study in assessing such hardship applications.

We believe that these avenues of relief can and should be fully explored by small refiners who are covered by the small refinery provision. In addition, we believe that it is appropriate to allow petitions to EPA for an extension of the temporary exemption based on disproportionate economic hardship for those small refiners who are not covered by the small refinery provision (again, per our discretion under section 211(o)(3)(B)); this would ensure that all small refiners have the same relief available to them as small refineries do. Thus, we are finalizing a hardship provision for small refineries in the RFS2 program, that any small refinery may apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per CAA section 211(o)(9)(B). We are also finalizing a case-by-case hardship provision for those small refiners that do not operate small refineries (section 80.1442(h)) using our discretion under CAA section 211(o)(3)(B). This provision will allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. In evaluating applications for this hardship provision EPA will take into consideration information gathered from annual reports and RIN system progress updates, as recommended by the SBAR Panel.

7. Conclusions

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities (see 74 FR 24904, *May 26, 2009*). A detailed discussion of the Panel's advice and recommendations is found in the Panel Report, located in the rulemaking docket. A summary of the Panel's recommendations is presented at 74 FR 25106 (*May 26, 2009*).

As required by section 604 of the RFA, we also prepared a final regulatory flexibility analysis (FRFA) for today's final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is available for review in the docket and is summarized above.

Many aspects of the RFS2 rule, such as the required amounts of annual renewable fuel volumes, are specified in EPAct and EISA. As discussed above, small refiners and small refineries receive an exemption from the RFS standards until January 1, 2011 and are not required to make expensive capital improvements like those required under other EPA fuels programs. Further the DOE small refinery study did not find that there was a disproportionate economic impact on small refineries as a whole as a result of this rule (and the majority of the refiners that meet the definition of a small refiner, also own refineries that meet the Congressional small refinery definition).

A cost-to-sales ratio test, a ratio of the estimated annualized compliance costs to the value of sales per company, was performed for gasoline and/or diesel small refiners. From this cost-to-sales test, it was estimated that all small entities have compliance costs that are less than one percent of their sales (a complete discussion of the costs to refiners as a result of the increased volumes of renewable fuel required by EISA is located in Section VII of this preamble).

As required by section 212 of SBREFA, EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. This guide will be available on the RFS website (www.epa.gov/otaq/renewablefuels/index.htm), and will be available 60 days after the rule is finalized.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531-1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. EPA has determined that this rule contains a Federal mandate that may result in expenditures of $100 million or more for the private sector in any one year, but the rule imposes no enforceable duty on any State, local or tribal governments. Nonetheless, EPA believes that today's action represents the least costly, most cost-effective approach to achieve the statutory requirements of the rule. The costs and benefits associated with the increased use of renewable fuels are discussed above and in the Regulatory Impact Analysis, as required by the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). This rule will be implemented at the Federal level and impose compliance costs only on transportation fuel refiners, blenders, marketers, distributors, importers, and exporters. Tribal governments would be affected only to the extent they purchase and use regulated fuels. Thus, Executive Order 13175 does not apply to this action. EPA specifically solicited comment on the proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 F.R. 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks and because it implements specific standards established by Congress in statutes.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. In fact, this rule has a positive effect on energy supply and use. By promoting the diversification of transportation fuels, the increased use of renewable fuels enhances energy supply. Therefore, we have concluded that this rule is not likely to have any adverse energy effects. Our energy effects analysis is discussed in Section VIII.B.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (“NTTAA”), Public Law No. 104-113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking changes the Renewable Fuel Standard (RFS) program at Title 40 of the Code of Federal Regulations, Subpart K which already contains voluntary consensus standard ASTM D6751-06a “Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels”. This rulemaking incorporates the most recent version of that standard (ASTM D-6751-08) and adds several more voluntary consensus standards: ASTM D-1250-08, “Standard Guide for Use of the Petroleum Measurement Tables”; ASTM D-4442, “Standard Test Methods for Direct Moisture Content Measurement of Wood and Wood-Base Materials"; ASTM D-4444, "Standard Test Method for Laboratory Standardization and Calibration of Hand-Held Moisture Meters"; ASTM D-6866-08 "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis"; ASTM E-711, "Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter"; and ASTM E-870, "Standard Test Methods for Analysis of Wood Fuels". Information about these standards may be obtained through the ASTM website (www.astm.org) or by calling ASTM at (610) 832-9585.

This rulemaking does not change these voluntary consensus standards, and does not involve any other technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards other than those described above.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA lacks the discretionary authority to address environmental justice in this rulemaking since the Agency is implementing specific standards established by Congress in statutes. Although EPA lacks authority to modify today's regulatory action on the basis of environmental justice considerations, EPA nevertheless determined that this rule does not have a disproportionately high and adverse human health or environmental impact on minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the Federal Register. A Major rule cannot take effect until 60 days after it is published in the Federal Register. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective July 1, 2010.

XII. Statutory Provisions and Legal Authority

Statutory authority for the rule finalized today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's rule, including the recordkeeping requirements, come from Sections 114, 208, and 301(a) of the Clean Air Act, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Administrative practice and procedure, Agriculture, Air pollution control, Confidential business information, Diesel Fuel, Energy, Forest and Forest Products, Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Petroleum, Reporting and recordkeeping requirements.

Dated: ______________________________

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Lisa P. Jackson,
Administrator.